COPY

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a copy of the foregoing Prefiled Testimony and Exhibits of Ohio Valley Gas, Inc. in Cause No. 43208 upon the following by personal service or by depositing same in the U.S. Mail, first class, postage prepaid to the following addresses:

FILED

MAR 3 0 2007

INDIANA UTILITY REGULATORY COMMISSION

The Indiana Office of Utility Consumer Counselor
Indiana Government Center North
100 North Senate Avenue, Room N501
Indianapolis IN 46204-3215

Dated this 30th day of March, 2007.

Ronald L. Loyd

Ronald L. Loyd
Vice President & General Manager
OHIO VALLEY GAS, INC.
111 Energy Park Drive
P. O. Box 469
Winchester IN 47394-0469
Telephone: 765-584-6842
Fax: 765-584-0826

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43208

PETITIONER'S EXHIBIT DJB

DIRECT TESTIMONY

OF

DAVID J. BEYNON

CHAIRMAN, PRESIDENT, CHIEF EXECUTIVE OFFICER

ON BEHALF OF

OHIO VALLEY GAS, INC.

MARCH 2007

PREPARED DIRECT TESTIMONY OF DAVID J. BEYNON

OHIO VALLEY GAS, INC.

1. Q. Will you please state your name and business address?

A. David J. Beynon, 111 Energy Park Drive, Winchester, Indiana.

2. Q. By whom are you employed?

A. The Petitioner in this proceeding, Ohio Valley Gas, Inc.

3. Q. What is your position with Petitioner?

A. Chairman, President, and Chief Executive Officer.

4. Q. When did you begin your employment with the Petitioner?

A. On September 1, 1953.

5. Q. Please summarize your educational background.

A. I graduated from the University of Nebraska in 1955 with a Bachelor of Science Degree in Electrical Engineering.

6. Q. Please summarize your professional experience and qualifications

A. USNR Active Duty 1955-1957. Westinghouse Electric Corporation from 1958-1960. I am a member of the Institute of Electrical & Electronic Engineers. I have been a director of the Company since August 1953. In February 1990, I was elected Chairman, President, and Chief Executive Officer of the Petitioner. Since 1960, I have been involved in almost every aspect of the gas business, including the selection of our data processing and personal computer systems, rate design, employee hiring and promotions, banking affiliations, insurance agents and companies and establishing an electronic service department, including installation and maintenance of our two-way radio system and numerous telemetry systems to keep track of the flow of natural gas. I have spent many days at a time in the districts observing various construction projects of the Petitioner. This has provided me with the opportunity to know our employees, gas systems, and customers. I maintain current personnel files and vehicle files, etc. in my office. I approve the expenditure of funds for all significant projects via the Company's annual construction budget. I was, for many years, a director of the Indiana Gas Association, Inc. Through this association, I have been able to exchange ideas and assist with the resolution of mutual problems with other natural gas utilities in the state.

7. Q. Have you previously testified before the Indiana Utility Regulatory Commission?

A. Yes, I have testified in proceedings on behalf of Petitioner and its parent company, Ohio Valley Gas Corporation.

8. Q. Is Petitioner a Corporation organized and existing under and by virtue of the laws of the State of Indiana?

A. Yes, Petitioner was incorporated on January 20, 1959.

9. Q. Where is Petitioner's principal office?

A. Winchester, Randolph County, Indiana.

10. Q. Is Petitioner a public utility under the laws of the State of Indiana and is it subject to the jurisdiction of the Indiana Utility Regulatory Commission?

A. Yes, we are a public utility and as such we are subject to the jurisdiction of the Indiana Utility Regulatory Commission.

11. Q. Please tell the Commission what areas are served by Petitioner.

A. We are authorized to, and do, operate a gas utility system which transports, distributes, and sells natural gas in the municipalities of Dugger, Farmersburg, Hymera, Riley, Shelburn, Sullivan and Winslow, plus the unincorporated communities of Arthur, Ayrshire, Blackhawk, Cass, Campbelltown, Curryville, New Lebanon and other rural areas, all located within Greene, Knox, Pike, Sullivan and Vigo Counties, in Indiana.

12. Q. Is this an interconnected system?

A. No. Petitioner has multiple delivery points from Texas Gas Transmission Corporation ("TGT"), and operates numerous segregated distribution systems in its certificated service territories.

13. Q. From whom is the natural gas transported and distributed through Petitioner's distribution systems purchased?

A. Petitioner purchases nearly all of its system supply gas through a natural gas broker, BP Canada Energy Marketing, Inc. Such purchases are made on a periodic, on-going basis as both fixed-price (futures) contracts and market-based (index) purchases.

14. Q. Does Petitioner have any other source(s) of gas?

A. At the present time, we do not. However, Petitioner has, at several locations, installed pipeline connections to allow for the purchase of locally produced, pipeline-quality natural gas as (when) available.

15. Q. Is Petitioner required to have a United States Department of Transportation ("DOT") Drug Testing Program and Alcohol Testing Program?

A. Yes.

16. Q. Does Petitioner have its DOT Drug Testing Program and Alcohol Testing Program in place and functioning, as required by DOT?

A. These programs were implemented in November 1990 and January 1995, respectively. The drug testing program provides for monthly random screenings on a randomly selected work day each month, as well as screenings under the categories of post accident, pre-employment, and for reasonable cause as defined therein. The alcohol testing program provides for screenings to be conducted for reasonable cause as defined therein.

17. Q. Who is responsible for the management of the DOT Drug Program?

A. I am. The Medical Review officer (MRO) makes his reports directly to me. After my review, these reports are sent to Ronald. L. Loyd, our Vice President and General Manager, who maintains the required files. Mr. Loyd randomly selects the work day of the month and randomly selects the employees to be tested through the use of a computer-generated randomizing process, and then provides a listing to me each month of employees selected for testing. He then advises those employees who have been so selected to report for the required screening. I am also responsible for the management of the DOT Alcohol Program as it currently applies to Petitioner.

18. Q. Are all of your employees covered under these programs?

A. All employees, considered by me to be employed in a safety-sensitive position, are included in our pool of employees subject to the random monthly selection process for drug screening. All employees, regardless of their position with the company are subject to testing under the alcohol program.

19. Q. Please describe the document marked Petitioner's Exhibit DJB-1.

A. It is a copy of Petitioner's Verified Petition in this Cause, filed with the Commission on January 8, 2007.

20. Q. Please describe the documents marked Petitioner's Exhibit DJB-2.

A. They are the required proofs of publication of the legal notice regarding the filing of our petition in this cause as received from those newspapers in which said notice was published.

21. Q. Please identify Petitioner's Exhibit DJB-3.

A. It is the certified resolution of Petitioner's Board of Directors ratifying and confirming the actions of our officers in commencing proceedings in this cause.

22. Q. Does the Petitioner regularly pay dividends to its shareholder?

A. No.

23. Q. Please identify Petitioner's Exhibit DJB-4.

A. This exhibit contains a facsimile copy of the required first notice of filing for rate increase as required by Commission rules. This notice was mailed to all residential customers between February 19 and February 22, 2007.

Inasmuch as the impact of the request for increased rates on a typical residential customer could not be determined at the time of the first notice, a second notice will be mailed to all residential customers at some point prior to the evidentiary hearing in this Cause. This second notice will provide additional general information regarding the request for increased rates and what effect such an increase, if granted by the Commission, would have on Petitioner's billings to a typical residential customer. Petitioner warrants that such a second notice will, in fact, be mailed to all of its residential customers and that a facsimile copy of such notice(s) will be entered into the record of this Cause as a late-filed exhibit, as necessary and appropriate.

24. Q. What is the basis for the proposed schedules of rates and charges in Exhibit RLL-4?

A. These rates and charges are intended to recover Petitioner's cost of service as determined and allocated among customer rate classes by Kerry A. Heid (Exhibit KAH-1) and produce a fair return on the original cost and fair value of Petitioner's investment in utility property used and useful for service to the public. The proposed rates should provide for a uniform and equitable return among all rate classes based on the cost of service study.

25. Q. Then you propose that your new rates be based on a cost of service study?

A. Yes. The rates we propose reflect, to the best of our ability, our true costs of service and virtually eliminate any inter-rate class subsidies that exist under the present rates and rate structure.

26. Q. Why does Petitioner need an increase in its rates and charges for natural gas service?

A. In Cause No. 42240, approved by the Indiana Utility Regulatory Commission on January 2, 2003, Petitioner was authorized to earn utility operating income of

$231,609. Exhibit SMK-3, Page 1, shows that Petitioner's unadjusted utility operating income per its books for the twelve months ended June 30, 2006 was a negative $156,089. When Petitioner's utility operating loss for the twelve months ended June 30, 2006 is adjusted for various fixed, known, and measurable adjustments, including weather normalization, among other adjustments, Petitioner's adjusted utility operating loss is $181,189. These results are especially alarming when Petitioner's investment in rate base of $2,318,288 as of September 30, 2006 (Exhibit SMK-3, Page 23) is considered. Petitioner's present rates and charges clearly do not produce a fair return on its used and useful property and therefore are unjust and confiscatory.

27. Q. What increase in revenues will be required to produce a fair return on the original costs and fair value of Petitioner's used and useful utility property and cover its cost of service?

A. The Petitioner's rates should be adjusted to generate $697,482 in additional annual revenue to produce annual Utility Operating Income of $414,872, resulting in a fair return of 10.08% on the depreciated original costs (Exhibit SMK-3, Page 30), and a 1.55% return on the fair value of Petitioner's investment in used and useful utility plant in service.

28. Q. What rate of return on equity are the proposed rates calculated to produce?

A. The rates and charges developed by Kerry A. Heid (Exhibit KAH-1) should allow the Petitioner to earn a return on common equity of 11.75% if, and only if, Petitioner does not incur costs or expenses greater than those incurred in the test year, as adjusted, and proposed revenues based on those rates are actually realized. Based upon the testimony of Paul R. Moul (Exhibit PRM), who developed Petitioner's proposed cost of equity capital, the management of Petitioner has determined that the proposed rates and charges should allow Petitioner to earn an acceptable and fair rate of return on the fair value of Petitioner's utility plant that is used and useful for providing natural gas service to Petitioner's customers.

29. Q. Does this conclude your direct testimony in this Cause 43208?

A. Yes, it does.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLAN OR PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	FILED JAN 0 8 2007 INDIANA UTILITY REGULATORY COMMISSION CAUSE NO. 43208

PETITION

Ohio Valley Gas, Inc. ("OVGI" or "Petitioner") respectfully requests authority to increase its rates and charges for gas utility service rendered by it; approval of new schedules of rates and charges applicable to such service; approval of various changes to its tariffs, rules and regulations for gas service, including increases in certain non-recurring charges; approval of a pipeline safety cost adjustment mechanism to recover costs of complying with federal law; approval to implement a normal temperature adjustment (NTA) mechanism in its tariffs; authority to use deferral accounting associated with the NTA and pipeline safety compliance costs; approval of changes in depreciation rates; and for approval as necessary and appropriate of all such relief as a component or components of an alternative regulatory plan or plans pursuant to IND. CODE 8-1-2.5. In support of this request, Petitioner respectfully represents to the Commission that:

1. Petitioner's Corporate and Regulatory Standing. Petitioner is a corporation duly organized and existing under the laws of the State of Indiana with its principal office located at 111 Energy Park Drive, Winchester, Indiana. Petitioner is a public utility as defined by IND. CODE §8-1-2-1(a) and an energy utility as defined by IND. CODE §8-1-2.5-2, and is therefore subject to regulation by the Commission in the manner and to the extent provided by the laws of the State of Indiana.

2. Petitioner's Operation and Utility Properties. Petitioner is authorized to and does provide gas utility service to more than 4,550 customers in 5 counties in west central Indiana. Petitioner provides such gas utility service by means of utility plant, property, equipment and related facilities owned, leased, operated, managed and controlled by it (collectively referred to as its "Utility Properties") used and useful for the convenience of the public in the production, treatment, transmission, transportation, distribution and sale of gas.

3. Petitioner's Operating Results Under Current Rates. Petitioner's existing basic rates and charges for gas utility service were established pursuant to the Commission's order dated January 2, 2003 in Cause No. 42240. Since its rates and charges for gas utility service were last established, Petitioner has continued to make significant capital expenditures for additions, replacements and improvements to its Utility Properties. Also, the fair value of Petitioner's Utility Properties and its utility service operating expenses and other costs have increased. As a result Petitioner's current rates and charges for gas utility service are unjust,

unreasonable, insufficient, discriminatory and confiscatory and should be increased. Petitioner's return on its Utility Properties is, and without relief as herein requested will continue to be below the level required to permit Petitioner to earn a fair return on the fair value of its Utility Properties, and to provide revenues to enable it to continue to attract capital for additions, make replacements and improvements to its Utility Properties at a reasonable cost, maintain and support its credit and assure confidence in its financial soundness. Petitioner therefore requests that new rates, charges, rules, regulations and regulatory proceedings be authorized that will enable it to realize a proper and adequate net operating income necessary and appropriate for the provision of safe, adequate and continuous gas utility service to the public.

4. Depreciation Rates. Rapid obsolescence of certain equipment requires changes to Petitioner's depreciation rates. Petitioner proposes that the annual depreciation rates for its office furniture and equipment (Account 391) and communications equipment (Account 397) be changed to 10.0% to reflect the much shorter useful lives of this equipment.

5. Normal Temperature Adjustment. To address the volatility of customer bills, send more accurate price signals and improve Petitioner's position with rating agencies and the financial community, Petitioner proposes adoption of a normal temperature, or "NTA" mechanism that will adjust current billings to Petitioner's residential and certain other customers on a real-time basis during certain heating periods to mitigate the effect of heating degree-day variations from the normal level of heating degree-days used to establish base rates. Petitioner proposes using deferred accounting for the effects of non-normal temperatures through the effective date of the approved NTA mechanism utilizing the same weather normalization methodology employed in this proceeding, and to recover from or refund to customers the effects

of non-normal temperatures through the interim use of a deferred "Type 2" NTA mechanism until such time as its "Type 1" mechanism is approved.

6. Pipeline Safety Compliance Cost Recovery Mechanism. Pursuant to provisions of the Federal Pipeline Safety Improvement Act of 2002, as re-authorized by Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the "Act"), Petitioner has incurred, and will continue to incur, incremental operating costs in order to assure compliance with the Act. The Federal Department of Transportation has adopted rules under the Act containing a compliance timeline requiring ongoing integrity management costs, and requiring Petitioner to adopt a comprehensive public education program. Significant resources are being devoted to meet the Act's requirements in a timely manner. This increase in operating expenses represents a significant new ongoing cost that needs to be reflected in Petitioner's rates. The magnitude and timing of these costs are uncertain and variable. Therefore, Petitioner proposes that these costs be recovered through a tracking mechanism authorized pursuant to IND. CODE §8-1-2-42(a). Petitioner also proposes to use deferral accounting for the costs incurred to comply with the Act through the effective date of the tracking mechanism, and to recover the deferred costs from customers in future periods through such tracking mechanism.

7. Tariffs, Rules and Regulations. Petitioner proposes and requests authority to revise its tariffs, rules and regulations for gas service, including, but not limited to, increases and adjustments to certain non-recurring charges and changes in its budget billing and alternative payment plans.

8. Test Year and Other Accounting and Procedural Matters. Petitioner proposes an adjusted test year of the twelve months ended June 30, 2006 and a cut-off date for determining the original cost and fair value of Petitioner's Utility Properties as of September 30, 2006 for

purposes of considering the relief hereby requested. Petitioner will cause notice of the filing of this Petition to be published in a newspaper of general circulation in Indiana and will provide its residential customers with a notice summarizing the nature and extent of the proposed rate changes affecting them as required by applicable statutes and Commission rules.

9. Applicable Statutory Provisions. Petitioner believes the provisions of IND. CODE §8-1-2-1 et seq., particularly §§8-1-2-4, 6, 7, 9, 24, 25, 38, 42, 61, 68 and 71, and IND. CODE §8-1-2-5-1 et seq., among others, are applicable to the subject matter of this Petition.

10. Attorneys for Petitioner and Service of Documents. Larry J. Wallace (1110-49), James A.L. Buddenbaum (14511-49) and Jerry R. Comeau (26310-53), Parr Richey Obremskey & Morton, 201 N. Illinois Street, Suite 300, Indianapolis, Indiana 46204, are counsel for Petitioner. Communications concerning this Petition should be addressed to:

Ronald L. Loyd
Vice President & General Manager
Ohio Valley Gas Corporation
111 Energy Park Drive
P. O. Box 469
Winchester, IN 47394-0469
(765) 584-6842, ext. 102
(765) 584-0826 (facsimile)
rloyd@ovgc.com

Larry J. Wallace (1110-49)
James A.L. Buddenbaum (14511-49)
Jeremy R. Comeau (26310-53)
Parr Richey Obremskey & Morton
201 N. Illinois Street, Suite 300
Indianapolis, IN 46204
(317) 269-2500
(317) 269-2514 (facsimile)
lwallace@parrlaw.com
jbuddenbaum@parrlaw.com
jcomeau@parrlaw.com

WHEREFORE, Petitioner respectfully prays that the Commission promptly conduct a pre-hearing conference and preliminary hearing and expeditiously make such investigation and hold such hearings as are necessary or advisable in this Cause, and thereafter issue an order:

a. finding that Petitioner's existing rates for gas utility service are unjust, unreasonable, insufficient, discriminatory, confiscatory and inadequate to provide a fair return on the fair value of Petitioner's Utility Properties used and useful for the convenience of the public in rendering gas utility service;

b. determining, and by order fixing, increased rates and charges to be applicable in the future to Petitioner's gas utility service in lieu of its existing rates and charges therefor;

c. authorizing and approving the filing by Petitioner of new schedules of increased rates and charges applicable to its gas utility service as necessary to constitute just, reasonable, sufficient and non-discriminatory rates;

d. authorizing Petitioner to implement a normal temperature adjustment and to defer, for future recovery, the interim effects of a normal temperature adjustment as described above and by Petitioner's evidence submitted in support thereof;

e. authorizing Petitioner to use deferral accounting and to recover its pipeline safety compliance costs as described above and by Petitioner's evidence submitted in support thereof;

f. authorizing changes in depreciation rates;

g. approving various changes in terms, conditions and provisions of Petitioner's rate schedules, tariffs, rules and regulations applicable to gas utility service as described herein and by testimony in support thereof;

h. approving such alternative regulatory plan or plans necessary and appropriate to facilitate and implement the regulatory authority, approvals, processes and actions herein proposed and requested; and

i. granting such other further and related relief as may be appropriate and proper.

Respectfully submitted,

By ______________________
Larry J. Wallace (1110-49)
James A. L. Buddenbaum (14511049)
Jeremy R. Comeau (26310-53)
PARR RICHEY OBREMSKEY & MORTON
201 N. Illinois Street, Suite 300
Indianapolis, IN 46204

Attorneys for Petitioner Ohio Valley Gas, Inc.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a copy of the foregoing has been served this 8th day of January, 2007, via United States Mail, postage-prepaid, and addressed as follows:

Indiana Office of Utility Consumer Counselor
Indiana Government Center North
100 N. Senate Avenue, Room N501
Indianapolis, IN 46204

____
Larry J. Wallace

PARR RICHEY OBREMSKEY & MORTON
201 N. Illinois Street, Suite 300
Indianapolis, IN 46204
Telephone: (317) 269-2500
Facsimile: (317) 269-2514

207122

with the Indiana Utility Regulatory Commission, in Cause No. 43208, for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations appli-cable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism, for approval of new depreciation rates as applicable to certain short-lived portions of its gas utility plan in service, for deferral and future recovery (or refund) of Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, appro-vals and deferrals.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center—South, 302 West Washington Street, Indianapolis, Indiana 46204-2284.

Ohio Valley Gas, Inc.
By: R. L. Lloyd
Vice President & General Manager

Feb. 2 11

Affidavit of Publication

STATE OF INDIANA
KNOX COUNTY } SS:

Before me, a Notary Public in and for the County of Knox and State of Indiana, personally appeared Vickie K. Palmer who, being duly sworn upon her oath, deposes and says, that she is the Publisher of The Sun-Commercial, a public (daily) newspaper of general circulation of Knox County, State of Indiana, printed in the English language and printed and published (daily) at Vincennes, Vincennes Township, Knox County, State of Indiana, and that said Sun-Commercial has been published continuously for more than five years last past, in said County and State; that the Notice of Publication, a true copy of which is hereto annexed, was duly published in said newspaper, on the following dates towit:

2nd day of February 20 07

_____ day of _____ 20 _____

_____ day of _____ 20 _____

_____ day of _____ 20 _____

_____ day of _____ 20 _____

_____ day of _____ 20 _____

And that all of said publication(s) were made in full compliance with the law.

Vickie K Palmer

Subscribed and sworn to before me this

2nd day of February 20 07

Brenda L Williams

BRENDA L. WILLIAMS
Knox County
My Commission Expires
January 21, 2008
NOTARY SEAL STATE OF INDIANA

My commission expires Jan. 21, 2008

Publisher's fee $ 60.72

Form Prescribed by State Board of Accounts

General Form No. 99P (Revised 1987)

Ohio Valley Gas Corp.
(Governmental Unit)

To: The Greene County Daily World

Greene County, Indiana

P.O. Box 129, Linton, IN 47441

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) - - number of equivalent lines 38

Head — number of lines .... ______

Body - -number of lines .... ______

Tail - - number of lines .... ______

Total number of lines in notice 38

COMPUTATION OF CHARGES

38 lines, 1 columns wide equals 38 equivalent lines at .3346 cents per line .... $ 14.71

Additional charge for notices containing rule or tabular work (50 percent of above amount) .... ______

Charge for extra proofs of publication (1.00 for each proof in excess of two) .... ______

TOTAL AMOUNT OF CLAIM .... $ 14.71

DATA FOR COMPUTING COST

Width for single column 7.4 ems

Number of insertions 1

Size of type 6 point

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I herby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Heather Rogers
Heather Rogers

Date: 06 Feb, 2007 Title: PUBLISHERS REPRESENTATIVE

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss:
Greene County)

ATTACH COPY OF ADVERTISMENT HERE

601-Legals

Legal #5012

Notice is hereby given that on the 8th day of January, 2007, Ohio Valley Gas, Inc., an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission, in Cause No. 43208, for authority to increase its rates and charges for the gas service rendered by it; for approval of new schedules of rates and charges; for approval of changes to its rules and regulations applicable to gas service; for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism; for approval of new depreciation rates as applicable to certain short-lived portions of its gas utility plant in service; for deferral and future recovery (or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs; and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and deferrals.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2284.

Ohio Valley Gas, Inc.
By: R.L. Loyd
Vice President & General Manager

Personally appeared before me, a notary public in and for said county and state, the undersigned Heather Rogers who, being duly sworn, says that she is Publishers Representative of the The Greene County Daily World newspaper of general circulation printed and published in the English language in the (city) (town) of Linton in state and county afore-said, and that the printed matter attached hereto is a true copy, which was duly published in said paper for 1 time(s), the dates of publication being as follows:

Feb 6th, 2007

Heather Rogers

Subscribed and sworn to before me this 9th day of FEB, 07.

[signature]
Notary Public

My commission expires: 07/2007

Form Prescribed by State Board of Accounts

General Form No. 99P (Rev. 1987)

Ohio Valley Gas, Inc.
e County, Indiana

To The Press-Dispatch (35-1132684)
Petersburg, Indiana 47567

PUBLISHER'S CLAIM

COMPUTATION OF CHARGES

0 lines, 0 column wide equals 0 equivalent lines
at 0 cents per line .... $ 20.00
Additional charges for notices containing rule or tabular work
(50 per cent of above amount) 0.00
Charge for extra proofs of publication ($1.00 for each proof in excess of two) 0.00
TOTAL AMOUNT OF CLAIM **$20.00**

DATA FOR COMPUTING CLAIM

Width of single column 8 ems
Number of insertions **1**

Size of type 8 point
Size of quad upon which type is cast **9**

Pursuant to the provisions and penalties of Chapter 155, Acts 1953, I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Frank Heuring

Date February 7, 2007 Publisher

LEGAL NOTICE

Notice is hereby given that on the 8th of January 2007, Ohio Valley Gas, Inc., an Indiana corporation, filed a petition with the Indiana Utility Regulatory Commission, in Cause No. 43208, for authority to increase its rates and charges for the gas service rendered by it; for approval of new schedules of rates and charges; for approval of changes to its rules and regulations applicable to gas service; for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism; for approval of depreciation rates applicable to certain short-lived portions of its gas utility plant in service; for deferral and future recovery (or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs; and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and deferrals.

A copy of the petition is on file with the Indiana Utility Regulatory Commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2284.

Ohio Valley Gas, Inc.
By: R. L. Loyd
Vice President and
General Manager
(February 7, 2007)

PUBLISHER'S AFFADAVIT

State of Indiana, ss:
Pike County

Personally appeared before me, a notary public in and for said county and state, the undersigned **Frank Heuring** who, being duly sworn, says that he is **Publisher of The Press-Dispatch a Weekly** newspaper of general circulation printed and published in the English language in the **City of Petersburg** in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for **1** time(s), the dates of publication being as follows: **February 7, 2007.**

Frank Heuring

Subscribed and sworn to before me this **7th** day of **February, 2007.**

Sara Ann Bachman

Sara Ann Bachman, resident Daviess County, Indiana
Notary Public
My commission expires September 16, 2009.

Form Prescribed by State Board of Accounts

General Form No. 99P (Revised 1987)

Ohio Valley Gas Corp.
(Governmental Unit)

Winchester, Indiana

To: ______________________

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) -- number of equivalent lines	
Head -- number of lines	1
Body -- number of lines	46
Tail -- number of lines	1
Total number of lines in notice	48

COMPUTATION OF CHARGES

48 Lines. 1 columns wide equal — equivalent lines at 2.87 cents per line	$ 137.76
Additional charge for notices containing rule or tabular work (50 percent of above amount)	0.00
Charge for extra proofs of publication ($1.00 for each proof in excess of two)	0.00
TOTAL AMOUNT OF CLAIM	$ 137.76

Ad # 11537483

Payment reference # 240715 (Must be included on check to assure proper posting to your account)

DATA FOR COMPUTING COST

Width of single column 7.4 ems

Number of insertions 1

Size of type 6 point

Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after showing all just credits, and that no part of the same has been paid.

Kimberly S. Wilkerson

Date: ________, 2007 Title: Legal Clerk

...GAL NOTICE
...reby given that on ... day of January 2007, ... Valley Gas, Inc., an In... corporation, filed a pe... tion with the Indiana Utility Regulatory Commission in Cause No. 43208, for authority to increase its rates and charges for the gas service rendered by it, for approval of new schedules of rates and charges, for approval of changes to its rules and regulations applicable to gas service, for authority to implement a Normal Temperature Adjustment mechanism and a pipeline safety compliance tracking mechanism, for approval of new depreciation rates as applicable to certain short-lived portions of its gas utility plant in service, for deferral and future recovery (or refund) of the Normal Temperature Adjustment and certain pipeline safety compliance costs, and for approval of an alternative regulatory plan or plans pursuant to I.C. 8-1-2.5 as reasonable, necessary and applicable to such authority, approvals and deferrals.
A copy of the petition is on file with the Indiana Utility Regulatory commission, Room E306, Indiana Government Center South, 302 West Washington Street, Indianapolis, Indiana 46204-2284.
Ohio Valley Gas, Inc.
By: R.L. Loyd
Vice President & General M...ager
11537483TSFeb. 16

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss:
Vigo County)

Personally appeared before me, a notary in and for said county and state, the undersigned Kimberly S. Wilkerson who, being duly sworn, says that she/he is Legal Clerk of the Tribune Star newspaper general circulation printed and published in the English language in the (city) (town) of Terre Haute, IN in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for one times ________, the dates of publication being as follows:

February 16-2007

Subscribed and sworn to before me this 16 day of Feb

Sandra Seeley
NOTARY PUBLIC Vigo COUNTY

OF... My commission expires 2-16-07

Form Prescribed by State Board of Accounts | General Form No. 99P (Revised 1995

Ohio Valley Gas
(Governmental Unit)

______________ County, Indiana

To: Sullivan Daily Times Dr
PO Box 130 Sullivan IN 47882-0130
Fed ID 35-1086779

PUBLISHER'S CLAIM

LINE COUNT

Display Matter (Must not exceed two actual lines, neither of which shall total more than four solid lines of type in which the body of the advertisement is set) -- number of equivalent lines . . . . ______

Head -- number of lines 30

Body -- number of lines . . . . ______

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COMPUTATION OF CHARGES

30 lines, 1 columns wide equals 30 equivalent lines at .539 cents per line . . . . $ 16.17

Additional charge for notices containing rule or tabular work (50 percent of above amount) . . . . ______

Charge for extra proofs of publication ($1.00 for each proof in excess of two) . . . . ______

TOTAL AMOUNT OF CLAIM . . . . $ 16.17

DATA FOR COMPUTING COST

Width of single column 12.5 ems

Number of insertions 1

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Pursuant to the provisions and penalties of Chapter 155, Acts 1953,

I hereby certify that the foregoing account is just and correct, that the amount claimed is legally due, after allowing all just credits, and that no part of the same has been paid.

Date: Feb. 15, 2007 Title: General Manager

PUBLISHER'S AFFIDAVIT

State of Indiana)
) ss:
Sullivan County)

Personally appeared before me, a notary public in and for said county and state, the undersigned Tom P. Gettinger who, being duly sworn, says that he is General Manager of the Sullivan Daily Times newspaper of general circulation printed and published in the English language in the (city) (town) of Sullivan in state and county aforesaid, and that the printed matter attached hereto is a true copy, which was duly published in said paper for 1 time, the dates of publication being as follows:

Feb. 5, 2007

LEGAL NOTICE
...ice is hereby given that on the 8th day of Ja...
...y 2007, Ohio Valley Gas Inc., an Indiana Cor...
...ation, filed a petition with the Indiana Utility
...gulatory Commission in Cause No. 43208 for
...hority to increase its rates and charges for the
...s service rendered by it, for approval of new
...hedules of rates and charges, for approval of
...anges to its rules and regulations applicable to
...s service, for authority to implement a Normal
...mperature Adjustment mechanism and a pipe...
...e safety compliance tracking mechanism, for
...proval of new depreciation rates as applicable
...certain short-lived portions of its gas utility
...ant in service, for deferral and future recovery
...r refund) of the Normal Temperature Adjust...
...ent and certain pipeline safety compliance
...sts and for approval of an alternative regula...
...ry plan or plans pursuant to IC 8-1-2.5 as rea...
...nable, necessary and applicable to such au...
...ority, approvals and deferrals.
...copy of the petition is on file with the Indiana
...ility Regulatory Commission, Room E306, In...
...ana Government Center South, 302 West
...ashing[illegible]et, Indianapolis, Indiana 46204
...84 [illegible]
...o Valley Gas, Inc.
by: R.L. Loyd
Vice President & General Manager
1st Ins 02-05-07 — 11

Subscribed and sworn to before me this 15 day of Feb., 2007.

Notary Public

My commission expires: Sept. 9 2007

RESOLUTION OF THE BOARD OF DIRECTORS

OF

OHIO VALLEY GAS, INC.

BE IT RESOLVED, that the Officers of the Company be and hereby are authorized to file a petition with the Indiana Utility Regulatory Commission for an increase in its rates and charges for the sale and transportation of natural gas and other miscellaneous service revenues (collection, returned check charges, reconnection charges, etc.) as soon as possible after January 2, 2007.

I, the undersigned, Scott A. Miller, Assistant Secretary of Ohio Valley Gas, Inc., hereby certify that the above and foregoing is a true and exact copy of a resolution adopted by the Company's Board of Directors at its meeting on the 26th of January, 2006, pertaining to filing for increased rates and charges with the Indiana Utility Regulatory Commission.

IN ATTESTATION OF WHICH, I have hereunto set my hand and affixed the official seal of said Company, this 3rd day of January, 2007.

Scott A. Miller

Scott A. Miller, Assistant Secretary

GENERAL SERVICE CUSTOMERS OF OHIO VALLEY GAS, INC.

FEBRUARY 19, 2007

ON JANUARY 8, 2007, OHIO VALLEY GAS FILED A PETITION WITH THE INDIANA UTILITY REGULATORY COMMISSION REQUESTING: AUTHORIZATION TO INCREASE ITS RATES AND CHARGES FOR GAS SERVICE AND APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES; APPROVAL OF CHANGES TO ITS GENERAL RULES AND REGULATIONS FOR GAS SERVICE; AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND A PIPELINE SAFETY COMPLIANCE TRACKING MECHANISM, AS WELL AS THE DEFERRAL OF RELATED COSTS FOR FUTURE RECOVERY; APPROVAL OF NEW DEPRECIATION RATES FOR CERTAIN SHORT-LIVED ITEMS IN ITS GAS UTILITY PLANT; APPROVAL OF AN ALTERNATIVE REGULATORY PLAN OR PLANS PURSUANT TO I.C. 8-1-2.5 AS REASONABLE, NECESSARY AND APPLICABLE TO SUCH APPROVALS AND DEFERRALS.

THE AMOUNT OF THE REQUESTED INCREASE, AS WELL AS THE EFFECT OF SAME AT VARYING USAGE LEVELS, WILL BE PROVIDED IN A SECOND NOTICE UPON OUR FILING OF OUR SUPPORTING EVIDENCE.

THE INDIANA UTILITY REGULATORY COMMISSION WILL CONDUCT A PUBLIC HEARING DURING WHICH OHIO VALLEY GAS WILL BE REQUIRED TO SHOW THAT THE REQUESTED ITEMS ARE JUSTIFIED. AN ORDER WILL THEN BE ISSUED BY THE COMMISSION BASED ON THE EVIDENCE PRESENTED.

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43208

PETITIONER'S EXHIBIT RLL

DIRECT TESTIMONY

OF

RONALD L. LOYD

VICE PRESIDENT & GENERAL MANAGER

ON BEHALF OF

OHIO VALLEY GAS, INC.

MARCH 2007

PREPARED DIRECT TESTIMONY OF RONALD L. LOYD

OHIO VALLEY GAS, INC.

1. Q. Will you please state your name and business address?

A. My name is Ronald L. Loyd. My business address is 111 Energy Park Drive, Winchester, Indiana 47394.

2. Q. By whom are you employed?

A. The Petitioner in this Cause, Ohio Valley Gas, Inc.

3. Q. What is your position with Ohio Valley Gas, Inc.

A. My position is that of Vice President & General Manager

4. Q. What is your educational background?

A. I hold a Bachelor of Science Degree in Chemical Engineering from Rose-Hulman Institute of Technology.

5. Q. What is your employment history?

A. I have been continuously employed by Ohio Valley Gas, Inc. since my graduation from Rose-Hulman in 1972. From 1979 through September 2004, my primary responsibilities as Chief Engineer included all matters relating to the construction, installation, operation and maintenance of the gas transmission and distribution systems owned and operated by Petitioner. In 1990, I was named as a Vice President of the Company, and continued in my role as Chief Engineer until October 1, 2004, at which time I assumed my present position as General Manager.

6. Q. What are your industry affiliations?

A. I am a member of the Gas Executive Committee of the Indiana Energy Association (IEA), and previously served as a Director of the former Indiana Gas Association (IGA, now a part of the IEA) and Indiana Underground Plant Protection Service (IUPPS). I have also served on numerous IGA/IEA committees and sub-committees, including Distribution System Engineering & Design, Measurement, Safety & Industrial Hygiene, and Personnel & Industrial Relations.

7. Q. Will you please tell the Commission what the document marked as Petitioner's Exhibit RLL-1 is?

A. This exhibit represents a determination of the Fair Value of Petitioner's Utility Plant in Service as of September 30, 2006.

8. Q. Will you please discuss the scope of Exhibit RLL-1?

A. This exhibit sets forth, by primary plant categories, the original cost, the current cost new, the percent condition and the resulting current cost less depreciation (i.e. fair value) of all gas utility property which Petitioner had in service as of September 30, 2006.

9. Q. Can you explain the basis and methods used in making the valuations set forth in Exhibit RLL-1?

A. The numbered plant account categories set forth in Column (1) of page 1(A) are in accordance with the "Uniform System of Accounts for Class A and B Gas Utilities," as established by the National Association of Regulatory Utility Commissioners. Original Cost balances for each of these accounts were determined from our plant account records. These balances reflect the cumulative cost of surviving plant property (i.e. year-by-year acquisitions less all subsequent retirements) and, in the final analysis, lead to a reasonable estimation of the Fair Value of Petitioner's Utility Plant in Service as of June 30, 2006. Page 1 of said Exhibit then updates said balances through September 30, 2006.

10. Q. How were the "Current Cost New" figures shown in Column (4) of page 1 derived?

A. Most of these figures were determined using cost-trending factors (see pages 2-13) taken from the January 1, 2006, issue of the "Handy-Whitman Index of Public Utility Construction Costs" (Bulletin No. 163). However, for Accounts 391 through 398, which contain General Plant items such as office furniture and equipment, laboratory equipment, tools, shop and garage equipment, transportation equipment, etc., the Column (4) figures were determined using cost-trending factors based on the Urban Consumer Price Index (CPI-U), which relates the relative cost of all items for urban consumers. This index is based on a reference period of 1982-1984, during which period the "average" of the monthly indices is set equal to 100.

11. Q. What is the "Handy-Whitman Index," and how is it used?

A. The "Handy-Whitman Index" is a standard reference on public utility construction costs which has been published continuously since 1924, and is comprised of index numbers for various utility plant accounts and for a number of sub-account categories of property which commonly occur in building construction, in general, and gas utility plant construction, in particular. It addresses six (6) geographic divisions of the United States, with Indiana being one (1) of twelve (12) states located in the North Central Division. The tabulated index numbers are an indication of the relative cost of materials, labor and equipment, by year, when compared to a certain base year (1973). The indices are based on studies (by others) of numerous statistical items pertaining to such things as wage rates, costs of living, material and equipment costs, etc. These indices are then used to approximate the replacement cost of a utility's total plant.

12. Q. Can you explain the term "cost-trending factor"?

A. A cost-trending factor is a conversion factor which represents the ratio of the acquisition cost of a given item of property between two dates. For example, if an item of property costs $10.00 in 1960, and the same item costs $40.00 in 2006, the cost-trending factor between these two dates would be 4.00 ($40.00 divided by $10.00). Conversely, if the original cost of a given item of property is $10.00 and the cost-trending factor is known to be 4.00, the Current Cost New of that same item would be $40.00 ($10.00 times 4.00).

13. Q. Are you convinced that the use of the "Handy-Whitman Index," as well as the Consumer Price Index where necessary, and the cost indices contained therein, is an appropriate means of estimating current (i.e. replacement) costs for Petitioner's existing gas utility plant?

A. Yes. It is my personal belief, and the contention of the Petitioner herein, that the use of these particular indices offers a reasonable, and appropriate method of estimating the reproduction cost of Petitioner's plant in service. With the subsequent application of a "percent condition" factor to each area of the plant account, Petitioner contends that it has taken into account both inflation, and the approximate current condition of its plant, in arriving at an estimate on the Fair Value of its existing Utility Plant in Service.

14. Q. What do you mean by "percent condition"?

A. Each element of Petitioner's plant has been assigned a Predicted Useful Life (PUL), in years, in order to arrive at an estimate of that element's remaining useful life. These predictions of "useful life" are based on Petitioner's knowledge of its system and the various components thereof, as well as, the methods used to install, protect, and maintain same. The PUL is not considered as an absolute length of time after which a given unit of plant account is automatically no longer used or useful. Rather, it is intended to represent an estimate of the "average" useful life of such plant account unit. The "percent condition" is simply the ratio of remaining useful life (i.e. the PUL less the age of the plant account unit in question) to the PUL itself. For example, if a surviving unit of plant account has a PUL of twenty (20) years, and was originally acquired in 1996, its "percent condition" in 2006, is estimated to be fifty percent (50%), since its remaining useful life of ten (10) years (2016 minus 2006), when divided by its PUL of twenty (20) years equals 0.50.

15. Q. What do the figures found on Line 3, Column (4) of page 1 represent?

A. These figures represent the total, cumulative current cost of the gas plant as of September 30, 2006. They represent actual original costs of all such surviving properties, grouped and adjusted (via cost-trending and percent condition factors) by vintage years to current procurement prices. They represent what it would cost to acquire those properties in new condition as of September 30, 2006.

16. Q. Do these figures include amounts for construction work-in-progress, materials and supplies, or working capital?

A. No. Allowances for these allowable items of rate base have not been included in this exhibit.

17. Q. Will you please summarize your findings?

A. As shown on page 1, Line 3, Petitioner's Total Utility Plant in Service as of September 30, 2006, was $7,317,965.02. When adjusted to 2006 prices the cost for comparable, new (100% condition) property is approximately $20,953,245. However, considering its overall existing 72% condition (see Line 27, Column (5) of page 1(A)), Petitioner's Total Utility Plant in Service has a current (9/30/06) Fair Value of approximately $15,087,596.

18. Q. Are you saying that the Fair Value of Petitioner's Total Utility Plant in Service at September 30, 2006, was at least $15,087,596?

A. Yes, I am.

19. Q. Does this conclude your testimony with regard to Exhibit RLL-1?

A. Yes, it does.

20. Q. Does Petitioner have any "transmission" pipelines as defined by Title 49, Part 192, "Transportation of Natural or Other Gas by Pipeline – Minimum Federal Safety Standards" promulgated by the U.S. Department of Transportation (U.S. D.O.T.)?

A. No, but it is not inconceivable that Petitioner may, through replacement or upgrade, have such pipelines in the future.

21. Q. Why is Petitioner requesting a Pipeline Safety Act (PSA) compliance tracking mechanism be approved in this Cause?

A. In addition to the possibility that Petitioner may, in the future, have "transmission" pipelines, and thus be subject to the provisions of the Pipeline Integrity

Management rule, it is reasonably certain that Petitioner will be subject to incremental costs necessary to ensure compliance with the yet-to-be finalized requirements of a Distribution Integrity Management Program (DIMP) rule, as required by The Pipeline Inspection, Protection, Enforcement and Safety (PIPES) Act of 2006 which will, when enacted, expand the philosophy of pipeline integrity management to the distribution systems of Petitioner and other local distribution companies (LDCs) by requiring the Pipeline and Hazardous Materials Safety Administration (PHMSA) to pass a final Distribution Integrity Management Program (DIMP) rule on or before December 31, 2007. The DIMP rule must, among other things, require that LDCs provide for the installation of an excess flow valve (EFV) on all new and replaced residential natural gas service line which operate continuously at a pressure in excess of 10 psig. The installation of such EFVs is, under current law, an option which must be offered to Petitioner's customers (at customer's expense) at the time of installation of new or replacement residential natural gas service lines.

The incremental costs associated with such new requirements can not be reasonably quantified at this time. However, Petitioner believes that all such reasonable and documented incremental costs required to ensure Petitioner's compliance with pipeline safety rules, whether now existing or promulgated in the future should be borne by the ratepayers to which such costs are reasonably applicable and not by its shareholders. Thus, Petitioner is proposing that such costs be recoverable via an approved Pipeline Safety Act compliance tracking mechanism, and that the deferred recovery of all such incremental costs, including remedial costs, if any, be authorized by the Commission.

22. Q. Does this conclude your testimony relative to Petitioner's request for approval of a Pipeline Safety Act compliance tracking mechanism and an Accounting Order to provide for the deferred recovery of incremental costs?

A. Yes, it does.

23. Q. Please identify Petitioner's Exhibit RLL-2 and explain its relevance to these proceedings.

A. Exhibit RLL-2 contains Petitioner's proposed <u>General Rules and Regulations Applicable to Gas Service ("Rules and Regulations")</u> which, together with Petitioner's various rate schedules, and the terms and conditions of service applicable thereto, comprise Petitioner's gas tariff. Collectively, these items form the basis and parameters for the utility services available customers of Petitioner and set forth the rights and obligations of both the Petitioner and its customers with respect to such services.

24. Q. Are the Rules and Regulations presented in Petitioner's Exhibit RLL-2 different from the existing Rules and Regulations under which Petitioner currently provides utility service to customers?

A. Yes. Petitioner is proposing numerous verbiage and grammatical changes to its existing, approved Rules and Regulations in some cases simply to clarify the intent of a rule, and in others to set forth Petitioner's desire to actually change, or add to, and existing rule, as follows:

- In Rule 3, Petitioner proposes to require customers to provide additional information relative to the level and type of service desired.
- In Rule 7, Petitioner proposes to strengthen the language regarding customer responsibility relative to providing access to premises.
- In Rule 14, Petitioner proposes to update the guidelines relative to the adjustment of bills due to meter error to comply with the existing Commission rule in subject regard.
- In Rule 15, Petitioner proposes to strengthen and clarify the question of warranty of title to the natural gas delivered to customers.
- In Rule 17, Petitioner proposes to strengthen and clarify the question of liability and responsibility for the natural gas delivered to customers.
- In Rule 18, Petitioner proposes to strengthen and clarify its responsibilities relative to continuity of service.
- In Rule 19, Petitioner proposes to update the rate of interest payable on customer deposits in accordance with the current Commission-approved rate.
- In Rule 20, Petitioner proposes to update and clarify various aspects of the monthly bills rendered to its customers.
- In Rule 24, Petitioner proposes to clarify that late payment charges will be applied to all accounts not paid on or before the due date.
- In Rule 29, Petitioner proposes to revise its existing Budget (Level) Payment Plan to allow for semi-annual review of account balances, and adjustment, as necessary, to a customer's required Monthly Payment

Amount due under the Plan in order to avoid unnecessarily large annual "true-up" adjustments to a Budget Plan customer's account balance. Petitioner also proposes to revise the manner in which it handles the annual "true-up" of account balances under the Plan so that both debit and credit balances are appropriately spread over the ensuing twelve-month period, thereby prospectively increasing or decreasing the Monthly Payment Amount due under the Plan from any individual customer in smaller increments from one Plan year to the next.

- In Rule 31, Petitioner proposes to strengthen and clarify its statement with regard to "force majeure".
- Rules 2, 4, 5, 6, 8, 9, 10, 11, 12, 13, 16, 21, 22, 23, 25, 26, 27, 28, 30, 32 and 34 all contain minor verbiage and/or grammatical changes to more clearly and appropriately present the intent of each respective rule.

25. Q. Does this complete your testimony with regard to Petitioner's Exhibit RLL-2?

A. Yes, it does.

26. Q. Please explain why Petitioner is proposing to implement a Normal Temperature Adjustment ("NTA") mechanism.

A. This proposal is being made as an integral part of Petitioner's efforts to stabilize recovery of its fixed costs; essentially all costs (except purchased gas costs) which are associated with providing service to its customers. Such costs, for purposes of a NTA mechanism, include operation expense (excluding purchased gas costs), maintenance expense, depreciation expense, taxes other than income, income taxes and capital costs.

Petitioner's existing rates, and the rates proposed in the instant Cause, have been designed on the basis of expected volumes of gas to be sold to its heat sensitive (i.e. heating) customers under "normal" weather conditions. Thus, Petitioner can recover its annual fixed cost of providing service <u>only</u> when (if) the weather-normalized level of sales volumes upon which Petitioner's rates are designed is actually achieved. Without such a mechanism, Petitioner will almost always either over-collect or under-collect its annual fixed costs and, conversely, its customers will almost always pay too much or too little for the service being rendered to them. Petitioner and its customers are, without a NTA mechanism, subject to the vagaries of Indiana's unpredictable winter weather. The NTA also helps to address the ever-increasing issue of volatility in Petitioner's billings to its customers. Such a mechanism will help to provide more stable annual bill amounts and mitigate the undesirable volatility in monthly billings during the heating season.

Finally, it is important to recognize that the NTA mechanism will help to send more accurate and timely price signals to Petitioner's customers compared to the current ratemaking methodology because it will stabilize that portion of the customers' bills related to the recovery of fixed costs while still recovering the actual variable costs of the gas itself on a metered/volumetric basis.

27. Q. What do you mean by "normal" weather (temperatures)?

A. Daily weather (specifically temperature) data which is compiled and maintained by weather stations operated under the auspices of the National Oceanic and Atmospheric Administration (NOAA), and located at various geographical sites around the U.S., relates heating degree day information on a running 30-year average. The current basis for these 30-year averages is the time period from 1971 through 2000. These 30-year average heating degree day numbers then are considered to be "normal" and are compared to current, actual heating degrees days for a given billing cycle to determine whether said cycle was "colder than normal" or "warmer than normal". Because Petitioner's NTA mechanism will require immediately available weather data on a daily basis, Petitioner must use data reported by those NOAA weather stations known as Class A stations.

28. Q. Has Petitioner determined which of these Class A NOAA weather stations are best suited for use in the implementation of its proposed NTA mechanism?

A. Yes. Based on the geographical spread of its customers, Petitioner is proposing to use weather data from the NOAA Class A weather station located at Indianapolis, IN for all of its customers to which the NTA will apply

29. Q. Please explain why temperature is such an important and appropriate factor to be considered in the gas utility ratemaking process.

A. As a part of the ratemaking process, both test-year costs (expenses) and test-year revenues have, historically, been weather-normalized. A weather-normalized test year used by the utility is recognized as the most representative "picture" of the operating conditions which may reasonably be expected to occur during the period in which the utility's approved rates and charges are to be in effect.

Since weather (specifically ambient air temperature) directly impacts the volume of natural gas used by heat-sensitive (i.e. heating) customers, a process whereby the effects of colder, or warmer, than normal temperatures on a gas utility's ability to recover its fixed costs can be mitigated is, in Petitioner's view, appropriate. The proposed NTA mechanism, as has been previously approved for other gas utilities in the state of Indiana, is such a process.

30. Q. Please explain how fluctuations in temperature impact, over time, a gas utility's heat-sensitive (heating) customers.

A. Since, under current and proposed rate design, Petitioner's billings to its customers are based primarily on the metered volume of gas consumed, billings to heating customers can, and do, vary widely depending on the number of heating degree days in any given billing cycle. These types of fluctuations can be particularly burdensome on people who operate on a fixed income basis. If actual temperatures are colder than normal, the typical gas customer will use more gas, and thus pay more than appropriate for service by virtue of his/her "overpayment" of fixed costs because such costs are currently being recovered primarily on a volumetric basis based on normal temperatures. Because Petitioner's level of "fixed" costs does not change with temperature, the greater gas volumes consumed, when applied against the same unit rate, generate greater non-gas revenues than the level established and approved by the Commission, thereby negatively affecting Petitioner's heating customers. Conversely, if actual temperatures are warmer than normal, the typical gas customer will use less gas, and thus pay less than appropriate for service by virtue of his/her "underpayment" of fixed costs because such costs are currently being recovered primarily on a volumetric basis based on normal temperatures. Because Petitioner's level of "fixed" costs does not change with temperature, the lower gas volumes, when applied against the same unit rate, generate lower non-gas revenues than the level established and approved by the Commission, thereby precluding Petitioner's from being able to appropriately recover its fixed costs.

31. Q. How will the proposed NTA mechanism help to alleviate the conditions to which you just referred?

A. The proposed NTA mechanism will help to mitigate the detrimental financial impact to Petitioner's heating customers which occurs when it is colder than normal. During such times, gas consumption is typically greater (for heating customers) and commodity prices are typically higher). This compounded effects of increased consumption and higher gas costs result in greater fixed cost recovery which is problematic for customers, regulators and utilities. The proposed NTA mechanism combats this compounded effect by ensuring that in periods of abnormally cold temperature customers only pay for the level of fixed costs appropriately allocated to them, and no more.

32. Q. Is there more than one way to implement a NTA mechanism?

A. Yes. There are two (2) basic approaches that have been utilized by other natural gas utilities in this regard. Petitioner's witness, Mr. Kerry Heid, addresses these methods in detail in Petitioner's Exhibit KAH.

33. Q. Which approach is Petitioner proposing for approval in this proceeding?

A. Petitioner is proposing to use the real-time, individual customer NTA mechanism (i.e. the Type 1 methodology described by Mr. Heid.)

34. Q. Why is Petitioner proposing to use a real-time, individual customer (Type 1) NTA mechanism?

A. By doing so, Petitioner will be adjusting its billings to customers on a real-time basis, tailored to the individual customer's consumption characteristics based on historical data, thereby allowing the customer to more readily link the resultant billing adjustments with the events (weather) which cause the adjustments. Additionally, Petitioner will benefit from the cash flow effect of the mechanism in a timelier manner than that provided by the Type 2 (deferred) mechanism.

35. Q. What are the most important characteristics/benefits of Petitioner's proposed NTA mechanism?

A. Consistent with previously approved NTA mechanisms, Petitioner believes that the most important characteristics/benefits of the proposed NTA mechanism include:

- The mechanism will be applicable to all heating customers served under Petitioner's general service rate (i.e. Rate 91).
- The mechanism adjusts Petitioner's billings to its customers only during the designated heating months set forth in Petitioner's witness Kerry Heid's testimony (Exhibit KAH) regarding the mechanics of the adjustment.
- The mechanism adjusts the volume of gas billed to each applicable customer to reverse the effect of abnormally warm or cold temperatures (low or high degree-day levels) for each applicable billing cycle.
- The mechanism is structured on a customer-specific basis (i.e. each customer will receive billing adjustments supported by the specific, historical gas consumption characteristics for that customer.

36. Q. How will Petitioner's proposed NTA mechanism "work"?

A. The proposed NTA mechanism will effectively adjust the metered heat-sensitive volume of natural gas consumed by each applicable customer during a given billing cycle to effectively weather-normalize the metered consumption utilized for the recovery of the fixed cost component of the customer's bill. The gas cost component of the bill would not be adjusted and would reflect actual metered consumption. Mr. Heid discusses the mechanics of the calculations used to make the appropriate adjustment(s), as well as other technical details of the NTA mechanism in Petitioner's Exhibits KAH.

37. Q. Does this complete your testimony with regard to Petitioner's proposed NTA mechanism?

A. Yes, it does.

38. Q. How are customer complaints handled?

A. Generally speaking, customer complaints, whether received directly from the customer or referred to Petitioner by the Commission, are assigned to the appropriate District Manager for resolution. Any complaint that may be filed with the Commission is initially referred to me (as General Manager) for response. Upon completion of the requisite "investigation" into the merits or validity of such a complaint and, as necessary and appropriate, discussing the nature of the complaint with the customer, a formal response is made to the Commission indicating whether or not the complaint has been resolved. We respond to each known complaint in a courteous and forthright manner, listening to the customer's position and reviewing the facts, and then attempt to resolve the matter to the satisfaction of all concerned parties.

39. Q. Does Petitioner maintain an internal fund to assist customers with the payment of natural gas billings?

A. Yes. Petitioner's internal fund has been entitled Gas Help Fund and has been in existence since 1982. The Gas Help Fund is administered by a third party. Contributions are received from various community service organizations, churches, customers and Petitioner's employees. Such contributions are then matched on a "dollar for dollar" basis by Petitioner's shareholders. Funds are maintained in FDIC-insured accounts in local financial institutions.

40. Q. Does Petitioner participate in the Help Thy Neighbor program, established by the state of Indiana, the Lilly Foundation and the large Indiana utilities, to assist certain customers who are not eligible for assistance with payment of their gas bill through federal or other programs?

A. Yes. While Petitioner has not contributed financially to the Help Thy Neighbor program, it does assist in the administration of the program by processing applications for assistance thereunder for its qualified customers. This process is initiated when a customer provides indication of an inability to pay and it is determined that their annual household income falls within the established limits of the program (i.e. 150-200% of the established federal poverty level).

41. Q. Does Petitioner promote energy conservation efforts to its customers? If so, what methods are used?

A. Yes. Petitioner uses its internet website, bill inserts/messages, radio spots, brochures, etc. to impress upon its customers various conservation techniques and the benefits of same. Also, Petitioner has for several years promoted energy efficiency through a rebate plan which offers cash incentives to customers upon installation of high-efficiency gas-fired equipment.

42. Q. Does Petitioner offer a Budget (Level) Payment Plan ("Budget Plan") to its residential customers?

A. Yes. Such a plan is not only offered, but is promoted by Petitioner as one way to assist its customers in the management of their natural gas bills. The particulars of Petitioner's Budget Plan are contained in Rule 29 of our proposed Rules and Regulations Applicable to Gas Service (see Exhibit RLL-2).

At December 31, 2006, 922 of Petitioner's residential heating customers (22.62% of Petitioner's 4,076 residential heating customers) were participating in the offered Budget Plan. The level (%) of participation has steadily increased from 19.85% since Petitioner's June 30, 2002 evaluation.

Petitioner also offers its Budget Plan to customers in certain other revenue classifications. As of December 31, 2006, 36 such non-residential heating customers were also participants in the Plan.

43. Q. How does Petitioner promote their Budget Plan and other available assistance programs?

A. Petitioner specifically promotes its Budget Plan via its internet website, radio spots, bill inserts, and through "Important Messages" printed directly on its monthly billing statements to customers. Such "Important Messages" also periodically discuss the existence of various assistance programs such as the federally-funded LIHEAP (Low Income Home Energy Assistance Program, generally known as EAP) and the aforementioned Help Thy Neighbor (HTN) program.

44. Q. Is Petitioner satisfied with the functionality and results of its Budget Plan?

A. No. Petitioner believes that certain changes to our existing Budget Plan, as discussed in my response to Q.24., should be made to enhance the review process, and where necessary and appropriate, the adjustment of monthly payments due under the Plan.

45. Q. Does Petitioner provide its customers with options relative to the payment of natural gas billings?

A. Yes. Petitioner continues to maintain a local customer service office in Sullivan, IN which is fairly centrally located amongst its customers. Customers may, at their convenience, thus pay their monthly billings from Petitioner either by U.S. mail, or in person at the customer service office.

Additionally, customers are offered the opportunity to have their natural gas billings paid via direct debit of a specified financial institution (bank) account. Participation in this Debit Payment Plan (DPP) is available to all customers and can be initiated by completion of an appropriate application which is included on the reverse side of Petitioner's monthly billing statements.

Finally, Customers can also pay their monthly billings via credit or debit card transaction through a third-party administrator of card payment plans.

46. Q. Has Petitioner made any recent changes in its customer billing process?

A. Yes. In October 2005, Petitioner installed new bill printing software to enable the issuance of full-page, statement-type billings to its customers, and subsequently installed mailing software to enable the use of the carrier route, bar-coded customer address to achieve the lowest cost post rate available. Prior to October

2005, Petitioner's billings to customers were printed on postcard stock. While the billings issued in this manner contained the minimal requisite information relative to metered consumption, amount billed (gross and net), due date, etc., the small size of the bill prevented Petitioner from providing additional information regarding consumption history, details of charges, comparative weather and other data, as well as the opportunity to include informative and flexible bill messages to its customers. in a timely and efficient manner.

47. Q. Please summarize Petitioner's Exhibit RLL-3.

A. This exhibit contains actual examples of Petitioner's statement-type bills, including a regular bill, a Budget Plan bill, a Final Bill and a Disconnect Notice, which provide Petitioner's customers with the following:

- A complete summary of the customers account activity since the previous statement, including account-specific information relative to the customer name, account number, mailing address, service address, service type (i.e. revenue class), previous balance due, payments received, if any, previous balance carried forward, current charges for services rendered in the current billing cycle and current account balance. Note: For those customers participating in Petitioner's Budget Plan, this portion of the statement also includes a Budget Payment Plan Summary, including previous budget payment due, budget payments received, if any, budget payments carried forward, if any, and the current budget payment due. For those customers participating in the direct debit payment plan, the date and amount of the bank transfer of funds is also reflected.

With regard to the amount of natural gas consumed during the current billing cycle, the billing statement provides previous and current meter readings and the dates of said readings, the number of days in the billing cycle, the metered volume of gas (in ccfs) and the thermal volume of gas (in therms). The statement also provides a bar chart which reflects the customer's usage for each of the last 13 months, the total consumption for the previous 12 months, and the average consumption per month for the previous 12 months. Additionally, there is a clear indication of the comparative degree day information provided as a percent warmer or colder than 1) the previous billing cycle, and 2) the same period from the prior year.

The bottom section of the front side of the statement billing provides information relative to Petitioner's address, telephone number(s), office hours, emergency contact number(s), and its website. It also provides space for Petitioner to relate general information in the form of various "Important Messages" to its customers. Topics periodically covered in this section include Energy Assistance Program information, Budget Plan information, Direct Debit Payment Plan information, Call Before You Dig information and contact numbers and various other information which may be of interest to Petitioner's customers.

In addition to the enrollment form for the Direct Debit Payment Plan, the reverse side of the statement bill contains expanded information on general payment terms, definitions and general information about estimated bills, final bills, etc. It also contains contact information for customers who may have billing questions, including information relative to contacting either the Indiana Utility Regulatory

Commission or the Indiana Office of Consumer Counselor at their respective toll-free telephone numbers and websites.

Based on undocumented feedback from numerous customers, the additional information provided on the new statement bill has proven to be generally helpful to, and well-received by Petitioner's customers.

48. Q. Does this complete your pre-filed, direct testimony in this Cause?

A. Yes, it does.

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INDEX OF EXHIBIT
EXHIBIT RLL-1

OHIO VALLEY GAS, INC.

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EXHIBIT RLL - 1
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OHIO VALLEY GAS, INC
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
9-30-06 AND THEIR 9-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

(1) Line No	(2)	(3) Original Cost	(4) Current Cost New	(5) Approx Percent Condition	(6) Cost Less Depreciation
1	Net Plant in Service at 6-30-06 per Plant Ledger	$7,241,701.76	$20,876,982	72%	$15,011,333
2	Net Plant Placed in Service 7-1-06 through 9-30-06	76,263.26	76,263	100%	76,263
3	Net Plant in Service at 9-30-06	$7,317,965.02	$20,953,245	72%	$15,087,596

OHIO VALLEY GAS, INC.
ORIGINAL COSTS OF PLANT SYSTEMS IN SERVICE
6-30-06 AND THEIR 6-30-06
CURRENT COST LESS DEPRECIATION VALUATIONS

LINE NO.	(1) ACCT NO.	(2) PLANT ACCOUNT DESCRIPTION	(3) ORIGINAL COST	(4) 6-30-06 CURRENT COST NEW	(5) APPROX. PERCENT CONDITION	(6) 6-30-06 COST LESS DEPRECIATION
		PRODUCT. & GATHERING PLANT				
1	325.2	Producing Leaseholds				
2	330	Prod. Wells - Well Constr.				
3	331	Prod. Wells - Well Equip.				
4						
		TRANSMISSION PLANT				
5	365.2	Rights of Way	$7,768.84	$7,768	100	$7,768
6	367	Mains	$1,502,531.18	$3,896,061	75	$2,930,197
7	369	Meas. & Reg. Sta. Equip.	$145,165.87	$248,827	76	$188,162
8			$1,655,465.89	$4,152,656		$3,126,127
		DISTRIBUTION PLANT				
9	374	Land & Land Rights	$17,871.33	$17,873	100	$17,873
10	376	Mains	$2,881,968.54	$11,185,211	74	$8,26[illegible]99
11	378	Meas.&Reg.Sta.Equip.-General	$36,935.62	$153,916	45	$6[illegible]03
12	379	Meas.&Reg.Sta.Equip.-CtyGate	$98,878.08	$201,922	70	$142,227
13	380	Services	$949,220.69	$2,677,526	77	$2,074,325
14	381	Meters	$260,670.16	$348,079	59	$204,693
15	383	House Regulators	$141,398.38	$225,274	65	$146,919
16	385	Indus.Meas.&Reg.Sta.Equip.	$1,461.45	$5,386	50	$2,693
17			$4,388,404.25	$14,815,187		$10,918,032
		GENERAL PLANT				
18	389	Land & Land Rights	$12,117.39	$12,117	100	$12,117
19	390	Structures & Improvements	$272,965.02	$587,439	71	$417,743
20	391	Office Furniture & Equip.	$30,598.53	$48,841	45	$22,013
21	392	Transportation Equip.	$367,471.10	$449,297	50	$226,639
22	394	Tools, Shop, & Garage Equip.	$378,816.49	$588,552	33	$192,947
23	395	Laboratory Equip.	$396.90	$708	5	$35
24	397	Communications Equip.	$134,843.27	$220,976	43	$95,680
25	398	Miscellaneous Equip.	$622.92	$1,209		
26			$1,197,831.62	$1,909,139		$967,174
27		TOTAL PLANT IN SERVICE	$7,241,701.76	$20,876,982	72	$15,011,333

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
365.2	1952		$ 47.00		$ 47
365.2	1964		2,622.85		2,623
365.2	1969		130.10		130
365.2	1970		2,216.48		2,216
365.2	1971		712.72		713
365.2	1972		503.33		503
365.2	1978		164.02		164
365.2	2002		1,320.00		1,320
365.2	2003		52.34		52
	TOTAL ACCT.		$ 7,768.84		$ 7,768
367	1952	S	$ 41,045.29	11.128205	$ 456,760
367	1963	S	15,757.20	7.355932	115,909
367	1964	S	44,454.80	7.000000	311,184
367	1969	S	96,508.84	5.864865	566,011
367	1970	S	78,504.38	5.425000	425,886
367	1972	S	62,252.35	4.520833	281,432
367	1973	S	1,094.71	4.340000	4,751
367	1975	S	20,625.98	3.312977	68,333
367	1976	S	7,181.37	2.952381	21,202
367	1978	S	13,113.26	2.480000	32,521
367	1979	S	2,911.46	2.333333	6,793
367	1980	S	3,822.56	2.106796	8,053
367	1981	S	62,686.02	1.878788	117,774
367	1986	S	16,081.86	1.764228	28,372
367	1988	S	48,752.71	1.613383	78,657
367	1993	S	22,991.30	1.675676	38,526
367	1998	S	1,881.92	1.456376	2,741
367	2001	S	14,139.15	1.404531	19,859
367	2002	S	948,726.02	1.382166	1,311,297
	TOTAL ACCT.		$ 1,502,531.18		$ 3,896,061
369	1964		$ 1,569.27	8.612903	$ 13,516
369	1974		1,013.05	4.643478	4,704
369	1982		528.65	2.243697	1,186
369	1984		3,410.25	2.197531	7,494
369	1985		4,307.34	2.170732	9,350
369	1988		23,712.65	1.907143	45,223
369	1989		6,068.00	1.816327	11,021
369	1990		7,339.86	1.810169	13,286
369	1992		20,127.55	1.679245	33,799
369	1993		2,882.75	1.638037	4,722

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR			SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
369	1994		$	12,356.47	1.570588	$	19,407
369	1995			3,298.42	1.530086		5,047
369	1996			927.56	1.487465		1,380
369	1997			803.24	1.435484		1,153
369	1998			20,757.03	1.420213		29,479
369	2001			34,712.91	1.335000		46,342
369	2004			1,350.87	1.271429		1,718
	TOTAL ACCT.		$	145,165.87		$	248,827
374	1951		$	80.00		$	80
374	1956			23.00			23
374	1967			7.00			7
374	1969			81.40			81
374	1982			13.50			14
374	1984			5.50			6
374	1985			81.00			8[illegible]
374	1986			152.97			15[illegible]
374	1987			904.50			905
374	1988			131.83			132
374	1989			43.75			44
374	1990			13.00			13
374	1991			35.00			35
374	1993			16,032.68			16,033
374	1995			52.05			52
374	1996			13.00			13
374	1998			27.00			27
374	1999			32.06			32
374	2001			10.00			10
374	2004			52.09			52
374	2006			80.00			80
	TOTAL ACCT.		$	17,871.33		$	17,873
376	1949	S	$	52.66	19.806452	$	1,043
376	1957	S		2,385.22	12.530612		29,888
376	1960	S		462.99	11.163636		5,169
376	1961	S		748.37	10.771930		8,061
376	1962	S		449.56	10.586207		4,759
376	1963	S		65,943.48	10.233333		674,822
376	1964	S		193,749.93	9.903226		1,918,749
376	1965	S		254.43	9.593750		2,441
376	1966	S		4,538.32	9.446154		42,87[illegible]
376	1967	P		573.68	5.565789		3,193

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1967	S	$ 84,211.34	8.898551	$ 749,359
376	1968	S	23,719.88	8.527778	202,278
376	1969	S	152,781.37	7.871795	1,202,664
376	1970	P	988.82	4.918605	4,864
376	1970	S	61,592.96	7.397590	455,639
376	1971	P	21,094.05	4.597826	96,987
376	1971	S	60,199.86	6.747253	406,184
376	1972	P	34,154.62	4.406250	150,494
376	1972	S	32,928.46	6.395833	210,605
376	1973	P	10,781.83	4.230000	45,607
376	1973	S	59,323.12	6.140000	364,244
376	1974	P	4,452.10	3.776786	16,815
376	1974	S	48,202.86	5.339130	257,361
376	1975	P	11,055.00	3.330709	36,821
376	1975	S	57,233.84	4.834646	276,705
376	1976	P	5,156.16	3.133333	16,156
376	1976	S	41,376.13	4.514706	186,801
376	1977	P	7,350.14	2.937500	21,591
376	1977	S	52,287.74	4.205479	219,895
376	1978	S	84,626.30	3.813665	322,736
376	1979	P	4,293.40	2.502959	10,746
376	1979	S	114,441.62	3.528736	403,834
376	1980	S	48,232.01	3.283422	158,366
376	1981	S	52,191.00	2.966184	154,808
376	1982	P	1,151.72	1.922727	2,214
376	1982	S	38,749.34	2.716814	105,275
376	1983	P	2,125.96	1.855263	3,944
376	1983	S	51,169.23	2.623932	134,265
376	1984	P	3,107.57	1.815451	5,642
376	1984	S	25,512.47	2.526749	64,464
376	1985	P	4,851.77	1.800000	8,733
376	1985	S	56,314.40	2.526749	142,292
376	1986	P	32,589.65	1.769874	57,680
376	1986	S	26,597.59	2.623932	69,790
376	1987	P	38,902.63	1.719512	66,894
376	1987	S	41,415.40	2.526749	104,646
376	1988	P	10,965.47	1.633205	17,909
376	1988	S	18,514.12	2.352490	43,554
376	1989	P	8,113.19	1.538182	12,480
376	1989	S	37,484.79	2.240876	83,999
376	1990	P	75,763.18	1.494700	113,243
376	1990	S	1,437.11	2.192857	3,151
376	1991	P	15,125.01	1.463668	22,138
376	1991	S	36,395.46	2.154386	78,410

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
376	1992	P	$ 11,780.73	1.443686	$ 17,008
376	1992	S	28,298.02	2.109966	59,708
376	1993	P	290,975.48	1.410000	410,275
376	1993	S	80,384.95	2.060403	165,625
376	1994	P	75,688.12	1.377850	104,287
376	1994	S	7,871.07	1.912773	15,056
376	1995	P	38,907.36	1.351438	52,581
376	1995	S	43.33	1.860606	81
376	1996	P	11,035.84	1.317757	14,543
376	1997	P	30,317.07	1.293578	39,217
376	1997	S	1,190.28	1.790087	2,131
376	1998	P	28,312.29	1.277946	36,182
376	1999	P	40,394.47	1.255193	50,703
376	1999	S	6,120.13	1.739377	10,645
376	2000	P	29,859.12	1.229651	36,716
376	2000	S	6,722.83	1.641711	11,037
376	2001	P	24,962.26	1.198300	29,91[illegible]
376	2001	S	3,926.40	1.607330	6,31[illegible]
376	2002	P	11,379.14	1.181564	13,445
376	2003	P	23,063.10	1.146341	26,438
376	2003	S	291.84	1.535000	448
376	2004	P	144,218.01	1.119048	161,387
376	2005	P	1,563.40	1.057500	1,653
376	2006	P	61,957.51	1.000000	61,958
376	2006	S	54,586.48	1.000000	54,586
	TOTAL ACCT.		$ 2,881,968.54		$11,185,211
378	1960		$ 225.00	8.745763	$ 1,968
378	1963		1,662.27	8.322581	13,834
378	1964		1,724.58	8.190476	14,125
378	1969		2,860.65	7.068493	20,220
378	1970		10,001.50	6.370370	63,713
378	1971		763.23	5.797753	4,425
378	1972		371.75	5.375000	1,998
378	1973		830.19	5.160000	4,284
378	1974		1,843.03	4.526316	8,342
378	1979		118.11	2.948571	348
378	1980		948.60	2.701571	2,563
378	1982		225.86	2.233766	505
378	1986		120.26	2.123457	255
378	1987		277.96	2.055777	571
378	1989		824.65	1.849462	1,525
378	1990		160.93	1.842857	297

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR			SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
378	1995		$	323.21	1.587692	$	513
378	2003			2,168.60	1.357895		2,945
378	2006			11,485.24	1.000000		11,485
	TOTAL ACCT.		$	36,935.62		$	153,916
379	1957		$	138.07	10.019231	$	1,383
379	1967			611.58	7.893939		4,828
379	1969			1,647.75	7.040541		11,601
379	1970			2,868.67	6.432099		18,452
379	1971			48.91	5.853933		286
379	1973			3,712.09	5.210000		19,340
379	1974			4,131.47	4.570175		18,882
379	1976			5,431.80	3.721429		20,214
379	1994			2,434.96	1.643533		4,002
379	1997			11,268.62	1.514535		17,067
379	2004			66,584.16	1.289604		85,867
	TOTAL ACCT.		$	98,878.08		$	201,922
380	1960	S	$	1,765.05	9.764706	$	17,235
380	1961	S		459.51	9.576923		4,401
380	1962	S		494.70	9.222222		4,562
380	1963	S		7,943.36	9.054545		71,924
380	1964	S		27,864.84	8.736842		243,451
380	1965	S		2,423.00	8.440678		20,452
380	1966	S		2,158.95	8.163934		17,626
380	1967	S		1,832.82	7.781250		14,262
380	1968	S		7,777.91	7.432836		57,812
380	1969	S		28,466.50	6.821918		194,196
380	1970	P		5,843.05	5.345679		31,235
380	1970	S		15,918.25	6.148148		97,868
380	1971	P		37.99	4.865169		185
380	1971	S		18,098.13	5.533333		100,143
380	1972	P		1,213.55	4.557895		5,531
380	1972	S		20,606.93	5.242105		108,024
380	1973	P		3,692.46	4.330000		15,988
380	1973	S		10,468.81	4.980000		52,135
380	1974	P		1,522.91	3.972477		6,050
380	1974	S		18,606.44	4.486486		83,478
380	1975	P		3,301.24	3.578512		11,814
380	1975	S		16,175.56	4.048780		65,491
380	1976	P		3,557.09	3.409449		12,128
380	1976	S		14,490.51	3.801527		55,086

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
380	1977	P	$ 2,348.15	3.207407	$ 7,531
380	1977	S	6,674.86	3.557143	23,743
380	1978	P	2,327.58	3.006944	6,999
380	1978	S	38,703.85	3.276316	126,806
380	1979	P	1,501.67	2.775641	4,168
380	1979	S	30,687.01	3.036585	93,184
380	1980	P	165.45	2.547059	421
380	1980	S	29,501.80	2.797753	82,539
380	1981	P	1,185.62	2.340541	2,775
380	1981	S	31,394.21	2.540816	79,767
380	1982	P	1,067.42	2.101942	2,244
380	1982	S	19,264.27	2.305556	44,415
380	1983	P	173.97	2.013953	350
380	1983	S	18,643.79	2.203540	41,082
380	1984	P	1,529.71	1.959276	2,997
380	1984	S	11,726.23	2.128205	24,956
380	1985	P	1,702.71	1.915929	3,26[illegible]
380	1985	S	30,598.77	2.110169	64,56[illegible]
380	1986	P	5,436.93	1.874459	10,191
380	1986	S	22,526.86	2.110169	47,535
380	1987	P	1,250.64	1.819328	2,275
380	1987	S	24,257.20	2.049383	49,712
380	1988	P	2,153.99	1.760163	3,791
380	1988	S	23,301.27	1.960630	45,685
380	1989	P	1,251.75	1.704724	2,134
380	1989	S	31,171.40	1.908046	59,476
380	1990	P	5,832.27	1.652672	9,639
380	1990	S	18,677.88	1.858209	34,707
380	1991	P	7,063.22	1.615672	11,412
380	1991	S	18,900.10	1.817518	34,351
380	1992	P	11,691.25	1.568841	18,342
380	1992	S	8,903.22	1.759717	15,667
380	1993	P	31,314.33	1.530035	47,912
380	1993	S	5,848.64	1.711340	10,009
380	1994	P	24,740.63	1.472789	36,438
380	1994	S	6,624.28	1.627451	10,781
380	1995	P	10,798.58	1.438538	15,534
380	1995	S	12,392.50	1.585987	19,654
380	1996	P	12,148.13	1.401294	17,023
380	1996	S	8,440.75	1.556250	13,136
380	1997	P	15,525.64	1.365931	21,207
380	1997	S	2,535.86	1.518293	3,850
380	1998	P	15,052.15	1.348910	20,30[illegible]
380	1998	S	2,189.29	1.500000	3,284

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR			SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
380	1999	P	$	25,693.73	1.316109	$	33,816
380	1999	S		2,624.87	1.464706		3,845
380	2000	P		15,930.18	1.277286		20,347
380	2000	S		7,370.87	1.406780		10,369
380	2001	P		23,695.34	1.233618		29,231
380	2001	S		4,175.26	1.368132		5,712
380	2002	P		7,572.60	1.196133		9,058
380	2002	S		3,732.47	1.335121		4,983
380	2003	P		14,264.72	1.145503		16,340
380	2003	S		3,074.78	1.280206		3,936
380	2004	P		44,142.58	1.101781		48,635
380	2004	S		3,614.48	1.200000		4,337
380	2005	P		7,479.52	1.053528		7,880
380	2005	S		4,121.05	1.048421		4,321
380	2006	P		2,960.39	1.000000		2,960
380	2006	S		4,822.46	1.000000		4,822
	TOTAL ACCT.		$	949,220.69		$	2,677,526
381	1953-1957		$	211.25	3.418182	$	722
381	1964			8,726.52	2.379747		20,767
381	1965			5,690.65	2.379747		13,542
381	1966			5,048.42	2.186047		11,036
381	1967			9,208.60	2.136364		19,673
381	1968			6,787.65	2.136364		14,501
381	1969			8,774.44	2.112360		18,535
381	1970			10,120.53	2.000000		20,241
381	1971			2,418.41	1.880000		4,547
381	1972			4,643.46	1.880000		8,730
381	1973			5,082.32	1.880000		9,555
381	1974			4,715.28	1.693694		7,986
381	1975			732.03	1.468750		1,075
381	1976			78.77	1.435115		113
381	1977			26.01	1.382353		36
381	1978			5,978.68	1.352518		8,086
381	1979			1,006.42	1.314685		1,323
381	1980			9,079.25	1.261745		11,456
381	1981			5,154.04	1.189873		6,133
381	1982			3,744.69	1.189873		4,456
381	1983			1,667.70	1.287671		2,147
381	1984			1,275.18	1.278912		1,631
381	1985			126.94	1.189873		151
381	1986			15,703.98	1.132530		17,785
381	1987			3,763.00	1.139394		4,288

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
381	1988	$	11,022.01	1.105882	$	12,189
381	1989		5,242.97	1.062147		5,569
381	1990		10,060.72	1.016216		10,224
381	1991		12,088.08	.989474		11,961
381	1992		8,879.59	.979167		8,695
381	1993		14,193.65	.984293		13,971
381	1994		13,726.64	.994709		13,654
381	1995		8,855.13	.989474		8,762
381	1996		8,315.95	.979167		8,143
381	1997		9,508.31	.959184		9,120
381	1998		3,468.71	.949495		3,294
381	1999		7,939.18	.969072		7,694
381	2000		4,224.50	.935323		3,951
381	2001		1,443.94	.930693		1,344
381	2002		6,577.19	.874419		5,751
381	2003		8,004.79	.954315		7,639
381	2004		4,564.84	1.044444		4,76[illegible]
381	2005		2,789.74	1.016216		2,83[illegible]
	TOTAL ACCT.	$	260,670.16		$	348,079
383	1964	$	2,659.52	4.195122	$	11,157
383	1966		2,737.64	4.300000		11,772
383	1968		274.38	4.246914		1,165
383	1969		2,616.74	4.144578		10,845
383	1970		3,547.44	3.739130		13,264
383	1971		225.59	3.510204		792
383	1972		1,653.96	3.440000		5,690
383	1973		460.09	3.440000		1,583
383	1974		978.22	3.245283		3,175
383	1975		755.91	2.752000		2,080
383	1976		1,508.74	2.606061		3,932
383	1977		2,075.17	2.529412		5,249
383	1978		1,818.63	2.388889		4,345
383	1979		2,580.74	2.011696		5,192
383	1980		2,638.28	1.711443		4,515
383	1981		2,253.11	1.638095		3,691
383	1982		2,011.78	1.585253		3,189
383	1983		1,749.59	1.556561		2,723
383	1984		2,733.65	1.495652		4,089
383	1985		2,596.81	1.451477		3,769
383	1986		867.32	1.457627		1,264
383	1987		5,307.75	1.415638		7,51[illegible]
383	1988		5,891.59	1.392713		8,205

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
383	1989	$	6,763.87	1.359684	$	9,197
383	1990		5,983.51	1.278810		7,652
383	1991		7,246.98	1.215548		8,809
383	1992		159.16	1.170068		186
383	1993		4,467.23	1.158249		5,174
383	1994		5,294.62	1.135314		6,011
383	1995		6,196.43	1.139073		7,058
383	1996		4,753.86	1.135314		5,397
383	1997		17,014.88	1.135314		19,317
383	1998		4,702.44	1.127869		5,304
383	1999		2,906.10	1.116883		3,246
383	2000		6,645.12	1.124183		7,470
383	2001		5,112.11	1.142857		5,842
383	2002		1,865.46	1.075000		2,005
383	2003		3,101.39	1.081761		3,355
383	2004		7,143.51	1.106109		7,902
383	2005		2,099.06	1.023810		2,149
	TOTAL ACCT.	$	141,398.38		$	225,274
385	1976	$	1,461.45	3.685714	$	5,386
	TOTAL ACCT.	$	1,461.45		$	5,386
389	1971	$	4,322.87	6.387097	$	4,323
389	1982		7,769.34			7,769
389	1993		25.18			25
	TOTAL ACCT.	$	12,117.39		$	12,117
390	1972	$	31,586.20	4.526882	$	142,987
390	1979		16,235.25	2.536145		41,175
390	1980		3,372.77	2.338889		7,889
390	1982		48,325.46	2.137056		103,274
390	1984		83,933.31	1.967290		165,121
390	1985		2,019.94	1.913636		3,865
390	1990		11,103.54	1.690763		18,773
390	1991		19,244.27	1.711382		32,934
390	1993		11,782.03	1.594697		18,789
390	1997		300.19	1.375817		413
390	2001		7,233.81	1.264264		9,145
390	2002		2,931.42	1.209770		3,546
390	2003		29,571.83	1.156593		34,203
390	2006		5,325.00	1.000000		5,325
	TOTAL ACCT.	$	272,965.02		$	587,439

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
391	1965	$	261.05	6.387097	$	1,667
391	1966		199.05	6.187500		1,232
391	1967		75.21	6.000000		451
391	1968		1,264.11	5.823529		7,362
391	1971		190.06	4.950000		941
391	1977		73.29	3.355932		246
391	1979		47.11	2.911765		137
391	1980		250.06	2.538462		635
391	1981		60.40	2.275862		137
391	1983		1,057.00	2.020408		2,136
391	1984		192.39	1.941176		373
391	1985		52.14	1.867925		97
391	1988		184.98	1.706897		316
391	1989		407.89	1.636364		667
391	1990		422.80	1.559055		659
391	1991		199.32	1.466667		292
391	1992		158.02	1.434783		227
391	1993		793.81	1.384615		1,09[illegible]
391	1994		6,341.92	1.356164		8,601
391	1995		338.14	1.320000		446
391	1996		528.49	1.285714		679
391	1998		10,673.30	1.222222		13,045
391	1999		464.67	1.207317		561
391	2000		251.67	1.171598		295
391	2001		1,145.26	1.131429		1,296
391	2002		528.32	1.118644		591
391	2003		2,374.76	1.087912		2,584
391	2005		170.20	1.036649		176
391	2006		1,893.11	1.000000		1,893
	TOTAL ACCT.	$	30,598.53		$	48,841

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
392	1986	$	26,308.05	1.800000	$	47,354
392	1993		34,068.18	1.384615		47,171
392	1995		33,248.33	1.320000		43,888
392	1996		26,040.73	1.285714		33,481
392	1998		41,150.17	1.222222		50,295
392	2000		23,809.72	1.171598		27,895
392	2001		67,407.05	1.131429		76,266
392	2003		37,498.67	1.087912		40,795
392	2004		40,305.81	1.070270		43,138
392	2005		37,634.39	1.036649		39,014
	TOTAL ACCT.	$	367,471.10		$	449,297

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR	SURVIVING PLANT BAL.	COST TREND FACTOR	CURRENT COST AT 6-30-06
394	1956	$ 1,449.00	7.333333	$ 10,626
394	1964	184.00	6.387097	1,175
394	1965	84.94	6.387097	543
394	1966	248.94	6.187500	1,540
394	1967	1,280.78	6.000000	7,685
394	1968	1,401.64	5.823529	8,162
394	1969	2,121.11	5.500000	11,666
394	1970	195.22	5.210526	1,017
394	1971	925.44	4.950000	4,581
394	1972	441.09	4.829268	2,130
394	1973	187.24	4.604651	862
394	1974	3,115.42	4.212766	13,125
394	1975	332.40	3.807692	1,266
394	1976	173.05	3.535714	612
394	1977	585.45	3.355932	1,965
394	1978	635.43	3.142857	1,997
394	1979	1,180.45	2.911765	3,437
394	1980	4,289.62	2.538462	10,889
394	1981	21,023.23	2.275862	47,846
394	1982	266.97	2.106383	562
394	1983	4,850.94	2.020408	9,801
394	1984	4,209.75	1.941176	8,172
394	1985	1,568.54	1.867925	2,930
394	1986	28,625.95	1.800000	51,527
394	1988	769.51	1.706897	1,313
394	1989	2,151.55	1.636364	3,521
394	1990	25,719.85	1.559055	40,099
394	1991	3,123.61	1.466667	4,581
394	1992	13,801.58	1.434783	19,802
394	1993	63,598.26	1.384615	88,059
394	1994	10,862.36	1.356164	14,731
394	1995	34,286.07	1.320000	45,258
394	1996	1,956.59	1.285714	2,516
394	1997	39,059.02	1.245283	48,640
394	1998	18,556.09	1.222222	22,680
394	2000	15,142.88	1.171598	17,741
394	2001	19,187.73	1.131429	21,710
394	2002	3,934.55	1.118644	4,401
394	2003	2,350.22	1.087912	2,557
394	2004	9,070.29	1.070270	9,708
394	2005	34,095.49	1.036649	35,345
394	2006	1,774.24	1.000000	1,774
	TOTAL ACCT.	$ 378,816.49		$ 588,552

OHIO VALLEY GAS, INC.
CURRENT COST OF PLANT

ACCT. NO.	VINTAGE YEAR		SURVIVING PLANT BAL.	COST TREND FACTOR		CURRENT COST AT 6-30-06
395	1987	$	396.90	1.783784	$	708
	TOTAL ACCT.	$	396.90		$	708
397	1967	$	1,350.00	6.000000	$	8,100
397	1968		1,194.00	5.823529		6,953
397	1972		2,366.54	4.829268		11,429
397	1979		1,689.40	2.911765		4,919
397	1980		2,420.91	2.538462		6,145
397	1981		965.98	2.275862		2,198
397	1982		402.09	2.106383		847
397	1984		3,109.29	1.941176		6,036
397	1985		393.73	1.867925		735
397	1986		987.74	1.800000		1,778
397	1988		1,214.83	1.706897		2,074
397	1989		2,007.73	1.636364		3,285
397	1990		133.27	1.559055		20[illegible]
397	1991		37,938.91	1.466667		55,644
397	1992		40,036.79	1.434783		57,444
397	1993		30,078.58	1.384615		41,647
397	1994		7,615.37	1.356164		10,328
397	1996		938.11	1.285714		1,206
	TOTAL ACCT.	$	134,843.27		$	220,976
398	1984	$	622.92	1.941176	$	1,209
	TOTAL ACCT.	$	622.92		$	1,209
	TOTAL SYSTEM	$	7,241,701.76		$	20,876,982

IURC GAS TARIFF

ORIGINAL VOLUME NO. 7

(Supersedes IURC Gas Tariff Original Volume 6)

of

OHIO VALLEY GAS, INC.

Filed with

Indiana Utility Regulatory Commission

OHIO VALLEY GAS, INC.
GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE

INDEX

OHIO VALLEY GAS, INC.

GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE

1. **RULES AND REGULATIONS ON FILE:**

A copy of all rates, as well as all rules and regulations under which gas service will be supplied, are posted or on file for the public's benefit in the offices of the Company and with the Indiana Utility Regulatory Commission ("IURC").

2. **WRITTEN APPLICATION OR CONTRACT REQUIRED:**

All applications for service will be made on the Company's standard application or contract form, which shall be signed by the Customer and accepted by the Company before service is supplied. A separate application or contract shall be made for service at each location/account. The Company may require up to two working days notice for all connections of existing natural gas service.

In any case where unusual construction or equipment expense is necessary to furnish the service, the Company may require a contract with reasonable guarantees as specified by the Company.

The Customer is also responsible for payment of all natural gas usage at a service location for up to three working days following notice to the Company to disconnect the natural gas service.

3. **DESCRIPTION OF DESIRED SERVICE:**

Upon request, the Customer shall furnish to the Company a list of the gas consuming equipment that is to be connected to the Company's gas supply on the premises. The Customer shall also advise the Company of their preference, if any, as to the pressure at which natural gas is to be delivered to Customer, and their preference, if any, regarding status as an "Off-System" customer, if applicable.

4. **COMPANY-OWNED PIPING AND EQUIPMENT:**

The Company shall furnish/install/maintain without charge to the Customer, as necessary and appropriate:

a. **Service Lines** consisting of gas piping extending from the Company's gas mains to the Customer's property line.

b. **Pressure Regulating Equipment**, as required by the Company to meet metering and delivery pressure requirements.

c. **Metering Equipment**, as required by the Company to determine the amount of natural gas consumed for billing purposes.

d. **Other Equipment**, if any, as required by the Company.

5. **LOCATION OF COMPANY REGULATORS, METERS AND APPURTENANCES:**

The Customer shall provide free of expense to the Company and at a location satisfactory to the Company a suitable place for necessary regulators, meter, or other equipment which may be furnished by the Company. Whenever possible, the meter setting shall be appropriately located outside and in a location which it is both readily accessible and reasonably protected from damage.

6. **EQUIPMENT LOCATION PERMIT OR EASEMENT:**

If the Customer is not the owner of the premises being served, or of any property between the premises to be served and the Company's main, the Customer shall obtain from the owner(s) of such properties certain permits or easements. These permits or easements shall be in a form satisfactory to the Company, and shall allow for the installation and maintenance of all piping and other gas equipment needed to supply gas to the Customer.

7. **ACCESS TO PREMISES:**

Employees and authorized agents of the Company shall have the right, at all reasonable times, to enter on the premises of the Customer. Such right of entry shall be used for inspecting, reading, testing, repairing, or replacing any Company-owned meters, regulators, or other equipment used to supply natural gas service, or for the removal of the aforesaid equipment upon termination of the contract or discontinuance of service.

The Customer shall take all necessary steps to appropriately restrain animals in order to prevent injury t Company employees or agents entering the Customer's property for the above reason(s). Any such injuries or other damages (and all costs associated therewith) which are incurred by the Company, its employees or agents while legally engaged in the above shall be the responsibility of the Customer. The Company, its shareholders, directors, officers, employees and agents specifically reserve the right to seek full and complete restitution, from any court of competent jurisdiction, for any claims, cause of action, losses or damages resulting from animal bites. This reservation of rights to seek restitution shall include but not be limited to seeking an equitable claim of subrogation.

8. **PROTECTION OF THE COMPANY'S PROPERTY:**

The Customer shall protect the Company's property on the Customer's premises from loss or damage and shall not permit anyone who is not an employee or agent of the Company to remove or tamper with the Company's property. If the Company's equipment is damaged or destroyed through the neglect of the Customer, the cost of repairs or replacement shall be paid by the Customer.

9. **CUSTOMER FURNISHED PIPING AND EQUIPMENT:**

The Customer shall furnish, install and maintain, at their expense, and in full compliance with Company prescribed standards, applicable Federal and state laws, rules and regulations, and local ordinances and codes the following:

a. **Yard Line** consisting of gas piping from the Customer's property line to the Company's meter setting. The Yard Line shall not be run under or through any portion of any building.

b. **Fuel Lines** consisting of all gas piping downstream of the Company's meter setting.

c. **Pressure Regulating Equipment**, as necessary to regulate the pressure of the gas after delivery to Customer.

d. **Metering Equipment**, as may be desired by the Customer to confirm the measurement of natural gas consumption. Such equipment shall be installed so as not to interfere with the operation of the Company's metering equipment.

The Company shall be under no obligation to inspect the piping and equipment of the Customer. Inspecting, reading, calibrating and adjusting any Customer-owned equipment shall be the responsibility of the Customer. Any future changes, repairs, replacements or relocations of the Customer's yard or fuel line(s), for whatever reason(s), shall be completed at the Customer's expense.

10. **POINT OF DELIVERY:**

The point of delivery of gas supplied by the Company shall be at the outlet of the meter. The Company will make the necessary connection at the point of delivery. Neither the Customer, nor anyone other than the Company, may lawfully alter or interfere with this connection, or with any of the equipment owned and maintained by the Company in any way.

11. **METERING:**

All natural gas used by the Customer will be measured by the meter(s) to be furnished and installed by the Company. Monthly bills shall be calculated upon the registration of said meter(s). Meters shall conform to the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana established by the IURC. If more than one meter is installed on the same premises, gas service to each meter shall be billed separately; however, if multiple meters are installed to serve the same rate classification strictly for the convenience of the Company, then only one monthly service charge for that rate class will be applied.

Customers receiving service under all Rate Schedules other than 11 and 41 shall, at the request of the Company, provide; 1) electricity (nominal 115 volts with the line fused at 15 amperes), and 2) access to a direct telephone line that is capable of allowing the Company to contact the metering location to obtain billing and flow information for the purposes of tracking daily and monthly usage at the Company's metering location.

12. **MEASUREMENTS:**

a. **Sales Unit** - The sales unit of the natural gas delivered by the Company to Customer shall be the Therm (Th). By definition, a therm is the amount of thermal energy equal to 100,000 British Thermal Units (BTUs). For example, where the heating value of the gas is 1000 BTU per standard cubic foot (SCF):

1 Therm (Th) = 100,000 BTU / 1,000 BTU/SCF = 100 SCF

b. **A Standard Cubic Foot (SCF)** of natural gas is that volume which occupies one (1) cubic foot of space when measured at sixty (60) degrees Fahrenheit and a pressure of 14.73 psia.

c. **Assumed Atmospheric Pressure** - The average absolute atmospheric pressure shall be assumed to be fourteen and four tenths (14.4) pounds per square inch. This standard shall be irrespective of the actual elevation of the point of delivery above sea level or variations in such atmospheric pressure from time to time.

d. **Flowing Temperature of Delivered Natural Gas** - At points of delivery where the installation of a recording thermometer or other temperature correcting device is provided, the indicated temperature of the gas flowing through the meter(s) shall be used in computing gas volumes. When such a device is not provided, the temperature of the gas shall be assumed to be sixty (60) degrees Fahrenheit.

13. **FAILURE OF METER:**

Whenever it is discovered that a meter is not recording correctly, adjustments shall be made correcting such inaccuracy in accordance with the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana. The volume of gas delivered by the Company to the Customer may be estimated, if necessary:

a. by using the registration of any Customer-owned meter or meters if installed and accurately registering, or,

b. by correcting the error if the percentage of error is ascertainable by calibration, test, or mathematical calculation, or,

c. by estimating the quantity of natural gas delivered based on deliveries made during periods under similar conditions when the meter was registering accurately.

14. **ADJUSTMENT OF BILLS DUE TO METER ERROR:**

If, upon test at thirty five (35) percent and eighty (80) percent of rated capacity, any measuring equipment is found to be, on average, not more than two (2) percent fast or slow, previous recordings of such equipment shall be considered commercially accurate in computing deliveries of natural gas; but such equipment shall be adjusted at once to record accurately.

If, upon test at thirty five (35) percent and eight (80) percent of rated capacity any measuring equipment shall be found to be, on average, more than two (2) percent fast or slow, previous recordings of such equipment shall be corrected to zero error for any period which is known definitely or agreed upon between the Company and the Customer. Such correction shall be for a period extending over one-half of the time elapsed since the date of last test, or one (1) year, whichever period is shorter, and the Customer's account shall be either credited or debited, as appropriate.

15. **WARRANTY OF TITLE TO GAS:**

The Company warrants title to and the lawful right to sell its system supply natural gas to Customer. Specifically, Company asserts that such natural gas shall be free from any and all claims, liens or other encumbrances. However, no such warranty shall attach to any natural gas received by Company for transportation to any "Off-System End User".

Off System End User shall be defined as a Customer for whom Company has no contractual obligation to provide natural gas from its system supply, and for whose natural gas requirements Company is not contractually committed to pay interstate pipeline charges of any kind.

16. **RESALE OF GAS:**

The Customer shall not pipe natural gas delivered by the Company off the premises being served, nor sell same to any other Customer or person.

17. **RESPONSIBILITY AFTER GAS IS DELIVERED BY COMPANY:**

Customer assumes liability and accepts responsibility for natural gas service on or about Customer's premises. Specifically, Customer premises shall include, but shall not be limited to, all pipe and equipment that is used and useful in connection with Customer's natural gas service and which is located downstream of the "Point of Delivery".

Customer shall hold Company harmless for all demands, claims, suits, judgments and executions, and for any personal injury or death, or damages to property (real, personal or mixed), due to Customer's use of natural gas on or about Customer's premises. Customer's duty to hold Company harmless shall not attach to injury or death, or for damages to property (real, personal or mixed) that may occur due to the sole negligence of the Company, its employees or agents.

18. **CONTINUITY OF SERVICE:**

Company shall employ natural gas industry best practices in its efforts to assure a continuous and adequate supply of natural gas for its Customers. Company does not, however, warrant or guarantee either a sufficient supply of natural gas or an adequate pressure for the natural gas delivered to Customer, and shall not be liable for damages due to interruptions in the supply of natural gas when such failure(s) are not due to the negligence of the Company.

19. **DEPOSIT TO ENSURE PAYMENT OF BILLS:**

a. **Residential Customers.** As set forth in the Rules, Regulations and Standards of Service for Gas Public Utilities in Indiana, the Company may require a cash deposit from an applicant for service or an existing Customer whenever standards of credit worthiness are not satisfied.

b. **Non-Residential Customers.** The Company shall require a cash deposit from an applicant for service or from an existing Customer as described in the Non-Residential Customer Security Requirements (See Rule No. 22 below).

c. **Interest.** Cash deposits of both residential and non-residential Customers which are held more than twelve (12) months shall earn interest from the date of deposit at an annual rate as prescribed, from time to time, by the IURC.

20. **MONTHLY BILLS:**

a. Bills for natural gas service will be rendered monthly unless otherwise specified. The term "month" for billing purposes shall mean the period between any two consecutive regularly scheduled readings of the meter(s) by the Company. Meter readings are to be taken as nearly as practicable every thirty (30) days.

b. When the Company is unable to read a meter after reasonable effort, the Customer will be billed based on an estimated consumption.

c. Failure to receive a bill in no way exempts the Customer from the provisions of these General Rules and Regulations Applicable to Gas Service, or the obligation to pay for the service(s) provided by Company.

d. The monthly billing for natural gas service will be considered paid when payment has been received by the Company at its designated address. The Company will not consider the payments as being made based on a postmark on the mailing envelope. Payments received after the due date printed on the monthly natural gas billings will be subject to the addition of a Late Payment Charge (Rule No. 24 below).

e. The Company may, at its sole discretion, require any Customer with monthly billings aggregating $25,000.00 or more to make payment to the Company in the form of a wire transfer directed to a bank account designated by the Company. Wire transferred funds shall be available to the Company on or before the due date printed on the monthly natural gas billings. The Customer may also be required to make a facsimile transmission to the Company, at a designated telephone (fax) number, setting forth the pertinent details of the wire transfer.

21. **DISCONNECTION OF RESIDENTIAL SERVICE:**

a. The Company may disconnect a residential service without request by the Customer and without prior notice only:

(1) if a condition dangerous or hazardous to life or property exists; or,

(2) upon receipt of an order by any Court, the Commission or other duly authorized public authority; or,

(3) if fraudulent or unauthorized use of gas is detected and the Company has reasonable grounds to believe the affected Customer is responsible for such use; or,

(4) if the Company's regulating or metering equipment has been tampered with and the Company has reasonable grounds to believe that the affected Customer is responsible for such tampering.

b. In all other instances the Company, upon providing a residential Customer with fourteen (14) days prior written notice, may disconnect service subject to the following:

(1) The Company shall postpone the disconnection of service for ten (10) days if, prior to the disconnect date specified in the disconnect notice, the Customer provides the Company with a medical statement from a licensed physician or public health official which must affirm that disconnection would be a serious and immediate threat to the health or safety of a designated

person in the household of the Customer. The postponement of disconnection shall be continued for one additional ten (10) day period upon the providing of an additional, and similar, medical statement from a licensed physician.

(2) The Company will not disconnect a residential service if the Customer shows cause, including financial hardship, for his inability to pay the full amount due and said Customer satisfies all of the following:

(a) Pays a reasonable portion (not to exceed the lesser of $10 or one-tenth (1/10) of the billed amount), unless the Customer agrees to pay a greater portion of the billed amount.

(b) Agrees to pay the remainder of the outstanding bill within three (3) months.

(c) Agrees to pay all undisputed future bills for service as they become due.

(d) Has not breached any similar agreement with the Company made pursuant to this rule within the past twelve (12) months.

Provided however, that the Company may add to the outstanding bill a Late Payment Charge not to exceed the amount set forth in Rule No. 24., and provided further, that the above terms of agreement shall be in writing and signed by the Customer and by a representative of the Company.

(3) The Company will not disconnect a residential service if a Customer is unable to pay a bill which is unusually large due to prior incorrect reading of the meter, incorrect application of the rate schedule, incorrect connection or functioning of the meter, prior estimates where no actual reading was taken for over two months, stopped or slow meters, or any human or mechanical error attributable to the Company, provided that the Customer satisfies all of the following:

(a) Pays a portion of the bill not to exceed an amount equal to the Customer's average bill for the twelve (12) bills immediately preceding the bill in question,

(b) Agrees to pay the remainder of the outstanding bill on a reasonable payment schedule.

(c) Agrees to pay all undisputed future bills for service as they become due.

Provided however, that the Company may not add to the unpaid balance of such a bill any Late Payment Charge or any other fee for the privilege of paying such a bill over the agreed period of time, and provided further, that the above terms of agreement shall be in writing and signed by the Customer and a representative of the Company.

c. Normally, the Company will disconnect service only between the hours of 8:00 a.m. and 3:00 p.m., prevailing local time. However, disconnections pursuant to Rule No. 21.a. are not subject to this limitation.

d. The Company will not disconnect service for non-payment on any day on which the Company office is closed to the public, or after twelve (12:00) noon of the day immediately preceding any day on which the Company office is not open to the public. However, disconnections pursuant to Rule No. 21.a. are not subject to this limitation.

22. **NON-RESIDENTIAL CUSTOMER SECURITY REQUIREMENTS:**

The Company may require a cash deposit from an applicant for service or from an existing Customer as set forth below:

a. **Cash Deposit Requirement.** The amount of the cash deposit shall be calculated based on the highest estimated monthly consumption multiplied by twice the rate in effect on the date of the application for service, or upon an existing Customer's receipt of a notice requiring a deposit.

The deposit calculation for a new Customer shall be based on reasonable estimated usage/consumption which shall include, but not be limited to, historical consumption on the property, any increased or decreased heating, processing load, etc., or an applicant's declaration of its projected usage and load.

The deposit calculation for an existing Customer shall be based on the highest monthly consumption during the previous five (5) years or, if a Customer less than five (5) years, the highest monthly consumption recorded since becoming a Customer, taking into consideration, without limitation, changes in the physical size of premises served, changes in usage or process application, removal or installation of different heating and processing equipment, etc.

b. **Exception To The Cash Deposit Requirement.** The Company shall have the discretion to waive the cash deposit requirement for both new applicants and existing Customers upon receipt of adequate assurance that the non-residential Customer is creditworthy. Adequate assurance of creditworthiness shall be demonstrated by the Customer by presenting all of the following to the Company, as requested/required:

(1) Their Dun & Bradstreet D-U-N-S No. and payment index which reflects a prompt payment history.

(2) A copy of their most recent audited financial report that includes a balance sheet showing assets exceeding liabilities, an income statement, and a cash flow statement; OR a verified or sworn financial report of the business entity that includes a balance sheet showing assets exceeding liabilities, an income statement, and a cash flow statement. Additionally, all owners of a business entity (Customer) may, upon a facts and circumstances determination made by Company, be required to provide a personal guaranty and personal financial statements to further ensure the payment of all natural gas bills rendered to the Customer by Company.

(3) Credit reference(s) from other public utilities stating that the entity has or had a prompt payment history on their utility bills and that no delinquency on such bills currently exists.

c. **Deferred Payment.**

(1) **New Customer.** Non-residential customers shall have their cash deposit, if not waived, paid prior to the establishment of natural gas service. The Company will, on request, consider allowing payment of the cash deposit on an installment basis contingent on the planned usage pattern of the new Customer and other factors which may affect the Customer's ability to pay. Provided that the Customer makes the initial installment payment in a prompt and timely manner, the Company shall initiate natural gas service. Should the Customer fail thereafter to tender payments on their installment payment plan, the Company shall be entitled to terminate natural gas service until the Customer has tendered the total amount of the deposit and paid, in full, all consumption billed to the Customer prior to termination of the service. A reconnect charge (See Rule No. 25 below) shall also apply to any Customer whose service is interrupted due to non-payment of a deposit installment.

(2) **Existing Customer.** The Company will, on request, consider allowing the payment of an existing Customer's cash deposit on an installment basis conditioned on all of the following:

(a) Terms mutually agreeable to both the Company and the Customer.

(b) The planned usage pattern of the Customer.

(c) Other factors which may affect the Customer's ability to pay.

Should the Customer fail to tender the initial installment or any installments thereafter, in a prompt and timely manner, the Company shall be entitled to terminate natural gas service until the Customer has tendered the total amount of the deposit and paid, in full, all consumption billed to the Customer prior to termination of the service. A reconnect charge (See Rule No. 25 below) shall also apply to any Customer whose service is interrupted due to non-payment of a deposit installment.

(3) **Applicability To Existing Non-Residential Customers.** The Company may require an existing non-residential customer to make an initial or additional cash deposit, if they are delinquent twice in a twelve (12) consecutive month period subsequent to the effective date of these General Rules And Regulations Applicable To Gas Service.

d. **Refunds.** The Company will not refund any cash deposit from a non-residential Customer until service is disconnected at the premises for which the deposit was collected. At the request of the Customer, but not more frequently than once during any given twelve month period, accrued interest will be transferred to the Customer's account.

e. **Public Authority Customers.** All Customers properly classified as public authority users shall be exempt from the requirement to provide a cash deposit until and unless an unexplained pattern of late (delinquent) payments develops.

23. **DISCONNECTION/NON-CONNECTION OF NON-RESIDENTIAL SERVICE FOR FAILURE TO SUPPLY CASH DEPOSIT:**

a. A new non-residential Customer shall not be entitled to natural gas service from the Company until an application for natural gas service is submitted, and accepted by the Company, and the required cash deposit is tendered to, or a waiver is granted by, the Company as described in Rule No. 22.

b. An existing non-residential Customer who fails within ten (10) calendar days of receiving written notice from the Company, to tender the required cash deposit as described in Rule No. 22., may have their natural gas service disconnected unless and until said Customer provides such deposit or obtains a waiver from the Company. A reconnection charge (See Rule No. 25 below) shall also apply to any Customer whose service is disconnected due to non-payment of the required deposit.

24. **LATE PAYMENT CHARGE:**

A Late Payment Charge, as shown on the applicable rate sheet will be applied to all accounts, including those enrolled in the Company's Budget (Level) Payment Plan, not paid on or before the due date as printed on the monthly natural gas billing

25. **RECONNECTION CHARGE:**

To cover the cost of disconnecting and reconnecting service for the same Customer at the same service address, a Reconnection Charge will be made in the amount shown on the applicable rate sheet. The Reconnection Charge shall be paid in full prior to the reconnection of natural gas service. If the disconnection period exceeds one year, the Company may waive the Reconnection Charge, provided the disconnection was not for a violation of any of the Company's Rules and Regulations.

26. **COLLECTION CHARGE:**

A collection charge, in the amount shown on the applicable rate sheet, may be made when it becomes necessary to send an employee or other authorized agent to a Customer's premises to collect a past due account. If the employee or other authorized agent is unable to make physical contact with the Customer, the hanging of a door card requesting the Customer to contact the Company shall constitute a basis for charging the Customer a Collection Charge. Customers enrolled in the Company's Budget (Level) Payment Plan will not be exempted from a Collection Charge for a collection trip to the Customer's premises for the purpose of collecting a past due Monthly Payment Amount.

27. **RETURNED CHECK CHARGE:**

A returned check charge, in the amount shown on the applicable rate sheet, will be levied on all checks received and on all authorized direct debits processed through the Automated Clearing House ("ACH") as payment of gas bills which are not honored, for whatever reason, by the Customer's bank. Additionally, any charges assessed by the Company's bank or the ACH processing system due to non-sufficient funds or a closed account will be added to the Customer's account with the Company and will be in addition to the Company's Returned Check Charge.

28. **THEFT OR UNAUTHORIZED USE OF GAS (A Class C infraction per IC 35-43-3-6):**

When theft or unauthorized use of gas (actual or attempted) is discovered, the Customer shall be charged minimum fee of One Hundred Dollars ($100.00). Further, the Customer shall be charged for the estimated volume of natural gas, as determined by the Company to have been so used. The Customer shall also pay any costs incurred by the Company to repair damaged or altered Company equipment, and/or to pursue legal remedy due to Customer's theft or unauthorized use.

29. **BUDGET (LEVEL) PAYMENT PLAN:**

The Company shall offer a Budget (Level) Payment Plan ("Plan") under which an eligible Customer may have their monthly billing amounts pre-determined (based on projected/estimated consumption), and equalized, for the duration of any given Plan year, as follows:

a. **Eligible Customer:** Residential, small commercial (including small farming operations, except for grain drying), public authority (including school corporations) and not-for-profit (including churches) system sales customers whose account(s) with the Company are, at the time of application, paid in full, shall be eligible to participate in the Plan. Eligible customers are generally limited to those served via a meter size of 800 scfh or less.

b. **Plan Year:** The Plan Year shall be defined as the twelve consecutive months beginning July 1 of one year and continuing through June 30 of the following year.

c. **Enrollment:** Any eligible Customer may enroll in the Plan at any time by contacting the local office of the Company, completing the prescribed Enrollment Form. The Customer will be enrolled in the Plan for the next billing cycle following receipt and acceptance, by the Company, of the completed Enrollment Form.

d. **Monthly Payment Amount.** The Monthly Payment Amount under the Plan shall be determined, by the Company, as follows:

   (1) **For existing accounts with a minimum twelve-month usage history**, by weather normalizing the most recent twelve months' usage for the account and pricing said normalized usage at the estimated rates for the ensuing Plan Year, or remaining portion of the current Plan Year, as appropriate.

   (2) **For new accounts or existing accounts with less than twelve months of usage history**, by establishing a weather normalized annual usage level (utilizing connected load and other information as may be available), and pricing said normalized usage at the estimated rates for the ensuing Plan Year, or remaining portion of the current Plan Year, as appropriate.

e. **Semi-Annual Review of Monthly Payment Amount:** Upon completion of the Company's billing cycles for June and December of each calendar year, the Monthly Payment Amount for each customer enrolled in the Plan shall be reviewed, and adjusted as necessary, based on account balance, usage history and updated pricing estimates for the new Plan Year or remaining portion of the current Plan Year, as applicable. Revised Monthly Payment Amounts will be appropriately communicated, in writing, to the applicable customers, and will become effective with the July, or January, billing cycle, as appropriate. If the semi-annual review determines that no change in the Monthly Payment Amount is required, the existing Monthly Payment Amount shall continue to be utilized until the next such semi-annual review and determination is completed.

f. **Annual "True-Up"of Plan Balance:** Coincident with the semi-annual review following the June billing cycle, each enrolled Customer's balance under the Plan will be "trued-up", assuming payment of the June Monthly Payment Amount will be paid when due. This "true-up" will result in the Plan account balance (debit or credit) being spread over the succeeding twelve-month period and, when combined with updated consumption and pricing estimates for the new Plan year, will be reflected in a revised Monthly Payment Amount.

g. **Customer Notices.** Each enrolled Customer shall be notified, by U.S. mail, of any revision to the Monthly Payment Amount established as the result of any semi-annual Plan review by the Company. Enrolled customers shall also be appropriately advised as to how any debit or credit balance (at the Plan year-end review) was applied to their account as set forth above.

h. **Failure to Pay Monthly Payment Amount by Due Date:** If an enrolled Customer fails to pay the required Monthly Payment Amount due under the Plan on or before the due date as printed on their monthly billing from the Company, the Customer will be subject to a Late Payment Charge as set forth in Rule No. 24. If a Customer fails to pay the required Monthly Payment Amount more than once in any twelve month period, the Customer may, at the Company's sole option, be removed from the Plan, and any debit balance existing under the Plan at that time shall be immediately due and payable in full. If there is a credit balance, said credit will be applied against future billings to the Customer at the current account, or refunded to the Customer at the sole discretion of the Company, if appropriate.

30. **RESTRICTIONS, LIMITATIONS, CURTAILMENTS AND PRIORITIES OF SERVICE:**

When sufficient volumes of gas are not available to the Company to meet all existing and reasonably anticipated demands, the Company shall have the right to restrict, limit, or curtail gas service within any of its systems, regardless of the class of service, and in accordance with the provisions of this Rule.

a. **Definitions.** For the purpose of this rule, certain terms shall have the following meanings:

(1) **"Off-System" Transportation Customer:** A Transportation Customer shall mean a Customer for which Company has no contractual obligation to provide natural gas from its system supply, and for whose natural gas needs and requirements Company is not contractually committed to pay interstate pipeline charges of any kind.

(2) **Interruptible Customer.** An Interruptible Customer shall mean a Customer purchasing natural gas on an interruptible service basis under any applicable rate schedule(s) of the Company.

(3) **Firm Customer.** A Firm Customer shall mean a Customers purchasing natural gas on a firm service basis under any applicable tariff schedule(s) of the Company.

(4) **Residential and Small Volume Commercial Customer.** Residential and Small Volume Commercial Customer shall mean any customer purchasing natural gas to provide service for one or more residential units or for one or more commercial units where the annual volume of gas required for each residential unit or for each commercial unit does not exceed the maximum annual usage specified in the Company's rate sheet(s) applicable to such customer(s). Customers who sell services or commodities to the general public are

considered commercial accounts, and shall include churches and other public and private not-for-profit groups and organizations.

(5) **Large Volume Firm Customer.** A Large Volume Firm Customer shall mean any Firm Customer whose annual usage of natural gas exceeds the minimum annual usage specified in the Company's rate sheet(s) applicable to such customer.

(6) **Large Volume Interruptible Customer.** A Large Volume Interruptible Customer shall mean any Interruptible Customer whose annual usage of natural gas exceeds the minimum annual usage specified in the Company's rate sheet(s) applicable to such customer.

(7) **Industrial Customer.** An Industrial Customer shall mean any Customer whose primary use(s) of natural gas include product processing, feed stock, or plant protection, and shall include any production entity that does not sell its products directly to the general public.

b. **Restrictions on New and Additional Service.** The Company shall have the right to refuse to provide new or additional service to applicants or existing customers as may be necessary due to a lack of system capacity or other physical or supply limitations.

c. **Normal Monthly Consumption of Large Volume Firm Customers and all Industrial Customers.** The Company shall have the right to establish a "Normal Monthly Consumption" for each Large Volume Firm Customer and each Industrial Customer in accordance with the following:

(1) **Normal Monthly Consumption.** The Normal Monthly Consumption of each Large Volume Firm Customer and each Industrial Customer shall be that volume of gas purchased by such Large Volume Firm Customer or Industrial Customer during each billing month of the Base Period specified by the Company.

(2) **Base Period.** The Base Period shall be the twelve consecutive billing months as may be specified by the Company, from time to time.

(3) **Notice to Large Volume Firm Customers and all Industrial Customers.** As soon as practicable after the provisions of this paragraph shall be invoked by the Company, the Company shall give written notice to each Large Volume Firm Customer and each Industrial Customer of its Normal Monthly Consumption as determined under provision c.(1) above.

d. **Interruptions, Limitations and Curtailments of Service.** The Company shall have the right to interrupt, limit, or curtail service to its Customers in the following order:

(1) **"Off-System" Transportation Customer.** Deliveries to each Transportation Customer in any billing month shall be limited to the lesser of its daily nomination, or the pipeline's daily allocated volumes to said Customer.

(2) **Interruptible Customers.** Deliveries to Interruptible Customers may be interrupted in accordance with the provisions of the applicable rate schedule.

(3) **Large Volume Firm Customers and all Industrial Customers.** Deliveries to Large Volume Firm Customers and all Industrial Customers in any billing month shall be limited to their

Normal Monthly Consumption, and may be curtailed on a pro-rata basis as specified by the Company.

(4) **Commercial Customers.**

(5) **Residential Customers.**

e. **Penalty for Unauthorized Gas Use.**

(1) If a Customer operating under a curtailment order/request issued by the Company takes delivery of volumes of natural gas in excess of 102% of the volume specified during any annual, seasonal, monthly or daily period, the Customer shall pay the Company an overrun penalty, in addition to all other charges and penalties payable under the Company's rate schedules, the greater of Three Dollars ($3.00) per Therm for all gas taken in excess of the specified volume, or the actual overrun penalties assessed to Company by its pipeline service provider.

(2) The Company shall have the right, without obligation, to waive the penalty for any unauthorized overrun if the Company's other Customers or its pipeline operations were not adversely affected by same. However, any Customer having such an unauthorized overrun, shall have its next allocation reduced by the amount of the unauthorized overrun.

f. **Applicability.** The terms, conditions and provisions of this Rule No. 30 shall take precedence over any other terms, conditions or provisions that may be contained in any Company tariff or rat schedule, or in any contract, agreement or other written instrument which may exist between the Company and any Customer.

31. **FORCE MAJEURE:**

a. Neither Company nor Customer shall be liable for any damages to the other due to any act, omission, or circumstances occasioned by or resulting as a consequence of any act of God, strike, lockout, act of the public enemy, war, blockade, insurrection, riot, epidemic, landslide, lightning, earthquake, fire, storm, flood, washout, arrest, restraint or suspension of lawful governmental authority, civil disturbance, explosion, breakage or accident to machinery or pipe; temporary failure of gas supply, binding order of any court or governmental authority, and any other cause, whether of the kind herein enumerated, or otherwise, not within the control of the party claiming suspension of performance and which, by the employment of due diligence, the other party is unable to prevent.

b. The occurrence of a cause or contingency resulting in non-performance shall not be lawful justification for relieving either Company or Customer of any duty or liability upon the finding of concurring negligence. Further, upon the finding of a failure of either Company or Customer to timely employ reasonable due diligence to remedy the cause for non-performance, eliminate the occurrence of a stated contingency, and to promptly reinitiate performance, the occurrence of said finding(s) shall be grounds for the imposition of liability for the failure to exercise the contractual duty to perform. Finally, no occurrence of a cause or contingency resulting in non-performance shall constitute lawful grounds for either Company or Customer to suspend, relieve, discharge or otherwise interrupt the prompt an timely payment of such sums and amounts that became due prior to the declaration of a force majeure.

32. **ASSIGNMENT:**

The benefits and obligations of any service agreement shall begin when the Company commences to supply natural gas service and shall inure to and be binding upon the heirs, successors, assigns, and executors or administrators of both the Company and the Customer.

33. **AGENTS:**

No agent has the power to amend, modify, alter, or waive any of the terms and conditions of any contract or agreement between the Company and any Customer or to bind the Company by making any promise or representation not contained therein.

34. **AMENDMENT OF GENERAL RULES AND REGULATIONS APPLICABLE TO GAS SERVICE:**

The Company reserves the right to modify, alter, or amend these General Rules and Regulations Applicable to Gas Service or to file additional General Rules and Regulations Applicable to Gas Service, as experience and conditions may suggest or as the Company may deem necessary in the conduct of its business. All such modifications, alterations, amendments, additions or deletions shall be subject to approval of the IURC.

OHIO VALLEY GAS, INC
15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

ACCOUNT NUMBER	9-10-4305-5-7
AMOUNT DUE BY 04/07/07	**169.57**
AMOUNT DUE AFTER 04/07/07	174.58

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

001968**001**009**SCH 5-DIGIT 47838

SULLIVAN IN 47882-7306

OHIO VALLEY GAS, INC
P O BOX 187
SULLIVAN, IN 47882-0187

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 9-10-4305-5-7

RATE: 91 DATE BILLED: 03/21/07 DATE DUE: 04/07/07
SERVICE ADDRESS:
SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		204.78
PAYMENT(S) RECEIVED - THANK YOU		204.78 CR
PREVIOUS BALANCE CARRIED FORWARD		.00
CURRENT CHARGES		
SERVICE AND DELIVERY	32.62	
GAS COSTS: 115 THERMS @ $1.1074/TH	127.35	
SALES TAX	9.60	
TOTAL CURRENT CHARGES		169.57

AMOUNT DUE BY 04/07/07 $ 169.57

AMOUNT DUE AFTER 04/07/07 $ 174.58

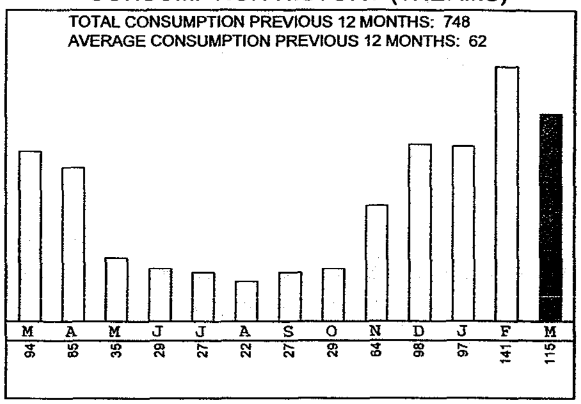
CONSUMPTION INFORMATION

PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/15/07	03/15/07	28

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
4885	4997	112

GAS USED IN CCFS		MULTIPLIER		GAS USED IN THERMS
112	X	1.0260	=	115

CONSUMPTION HISTORY (THERMS)



Current period was 37% WARMER than previous period.
Current period was 10% COLDER than same period last year.

IMPORTANT MESSAGES FROM OHIO VALLEY GAS TO BETTER SERVE YOU

Energy Assistance Program (EAP): Financial assistance is available for residential customers with household income at or below 150% of the poverty income level. Example: a family of four with income of $30,000 or less would be eligible for assistance. Contact your local Community Action Agency for further information and/or to apply for this assistance as soon as possible.

Help Thy Neighbor Energy Assistance Fund (HTN): Financial assistance is available for residential customers with household income between 150% and 200% of the poverty income level and who are at risk of having their gas service disconnected for non-payment. Example: a family of four with income of $30,000 to $40,000 would be eligible for assistance. Call the Ohio Valley Gas office number shown on this bill during regular business hours for further information and/or to apply for this assistance as soon as possible.

15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (812) 268-6368
TOLL FREE 1-(877) 884-6368

BUSINESS HOURS
MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

<u>ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.</u>
TELEPHONE (812) 268-6369
TOLL FREE 1-(877) 884-6368

ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY		
M ☐	Amt Received	$________
ND ☐	Amt Owed	$________
CK ☐	Change	$________

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

Payment will be deducted from your financial institution on the due date. Your bill will state the due date and amount to be deducted. Please continue bill payments until your bill states that a bank transfer will be made.

Phone (Home) Work OVG Account Number (See Reverse)

Name on Financial Institution Account Customer Name (See Reverse)

Routing Number (9 Digit) Financial Institution Account Number

(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)

Signature Date

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For the above to be acknowledged, you must "x" the box on the reverse of this form.

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CURRENT CHARGES:
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- *Gas Costs* – The market cost of natural gas consumed by the customer.

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ESTIMATED BILLS: An estimated bill utilizes estimated consumption when actual meter readings are not obtainable. An "E" following the meter reading indicates an estimated reading.

FINAL BILLS: A final bill is issued when an account is closed and a final meter reading is obtained. If an account has a security deposit, the deposit and accrued interest will be applied to the final bill.

BILLING QUESTIONS: If you have questions about your bill or our service, please visit or call your District Office during business hours at the telephone number on the reverse; e-mail your District Office at our website; or write to the address shown on the reverse. **INDIANA CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas, you may call the Indiana Utility Regulatory Commission (IURC) toll-free at 1-800-851-4268 from 8:00a.m. to 5:00p.m. weekdays, or visit the IURC website at www.in.gov/iurc. Residential customers may also call the Office of the Utility Consumer Counselor (OUCC) toll-free at 1-888-441-2494, or visit the OUCC website at www.in.gov/oucc. **OHIO CUSTOMERS:** If your questions are not resolved after you have contacted Ohio Valley Gas you may call the Public Utilities Commission of Ohio (PUCO) toll-free at 1-800-686-7826 or 1-614-466-3292, or for TDD/TTY toll-free at 1-800-686-1570 or 1-614-466-8180, from 8:00a.m. to 5:30p.m. weekdays, or visit the PUCO website at www.PUCO.ohio.gov.

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OHIO VALLEY GAS, INC
15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

ACCOUNT NUMBER	9-10-4025-1-6
AMOUNT DUE BY 04/07/07	**88.00**

A BUDGET PAYMENT RECEIVED AFTER THE DUE DATE WILL BE SUBJECT TO A LATE PAYMENT CHARGE.

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

002007**001**009**SCH 5-DIGIT 47838

SULLIVAN IN 47882-7321

OHIO VALLEY GAS, INC
P O BOX 187
SULLIVAN, IN 47882-0187

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 9-10-4025-1-6

RATE: 91 DATE BILLED: 03/21/07 DATE DUE: 04/07/07

SERVICE ADDRESS:

SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		172.23
PAYMENT(S) RECEIVED - THANK YOU		120.00 CR
PREVIOUS BALANCE CARRIED FORWARD		52.23
CURRENT CHARGES		
SERVICE AND DELIVERY	36.37	
GAS COSTS: 137 THERMS @ $1.1074/TH	151.71	
SALES TAX	11.28	
TOTAL CURRENT CHARGES		199.36
ENT ACCOUNT BALANCE*		251.59

*his represents the amount you would owe, if you left the Budget Plan.

BUDGET PAYMENT PLAN SUMMARY

PREVIOUS BUDGET PAYMENT DUE	104.00
BUDGET PAYMENTS(S) RECEIVED - THANK YOU	120.00 CR
BUDGET PAYMENT DUE CARRIED FORWARD	16.00 CR
CURRENT BUDGET PAYMENT DUE	104.00

AMOUNT DUE BY 04/07/07 $ 88.00

CONSUMPTION INFORMATION

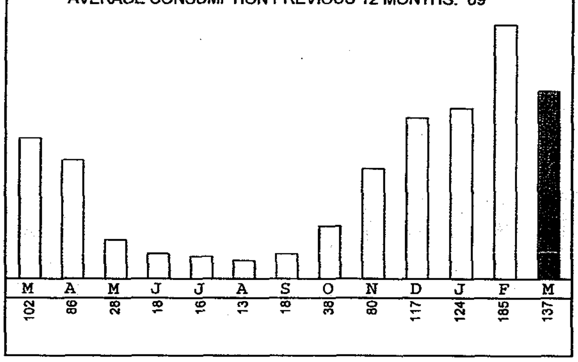
PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/15/07	03/15/07	28

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
3494	3628	134

GAS USED IN CCFS		MULTIPLIER		GAS USED IN THERMS
134	X	1.0260	=	137

CONSUMPTION HISTORY (THERMS)

TOTAL CONSUMPTION PREVIOUS 12 MONTHS: 825
AVERAGE CONSUMPTION PREVIOUS 12 MONTHS: 69



Current period was 37% WARMER than previous period.
Current period was 10% COLDER than same period last year.

IMPORTANT MESSAGES FROM OHIO VALLEY GAS TO BETTER SERVE YOU

Energy Assistance Program (EAP): Financial assistance is available for residential customers with household income at or below 150% of the poverty income level. Example: a family of four with income of $30,000 or less would be eligible for assistance. Contact your local Community Action Agency for further information and/or to apply for this assistance as soon as possible.

Help Thy Neighbor Energy Assistance Fund (HTN): Financial assistance is available for residential customers with household income between 150% and 200% of the poverty income level and who are at risk of having their gas service disconnected for non-payment. Example: a family of four with income of $30,000 to $40,000 would be eligible for assistance. Call the Ohio Valley Gas office number shown on this bill during regular business hours for further information and/or to apply for this assistance as soon as possible.

15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (812) 268-6368
TOLL FREE 1-(877) 884-6368

BUSINESS HOURS
MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

<u>ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.</u>

TELEPHONE (812) 268-6369
TOLL FREE 1-(877) 884-6368

ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY		
M ☐	Amt Received	$________
ND ☐	Amt Owed	$________
CK ☐	Change	$________

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

Payment will be deducted from your financial institution on the due date. Your bill will state the due date and amount to be deducted. Please continue bill payments until your bill states that a bank transfer will be made.

Phone (Home) Work OVG Account Number (See Reverse)

Name on Financial Institution Account Customer Name (See Reverse)

Routing Number (9 Digit) Financial Institution Account Number

(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)

Signature Date

I authorize Ohio Valley Gas to debit the financial institution account listed for monthly payment of my bill. I understand I may stop this service ten (10) or more business days before the due date by calling the telephone number on the reverse.

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OHIO VALLEY GAS, INC
15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

ACCOUNT NUMBER	9-09-4780-7-6
AMOUNT DUE BY 03/30/07	**270.36**
FINAL BILL	

☐ PLACE AN "X" IN THE BOX IF YOU INCLUDED DIRECT DEBIT INFORMATION ON THE REVERSE.

002462**014**012*****MIXED AADC 473

WINSLOW IN 47598-0136

OHIO VALLEY GAS, INC
P O BOX 187
SULLIVAN, IN 47882-0187

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

ACCOUNT ACTIVITY

ACCOUNT NUMBER: 9-09-4780-7-6

RATE: 91 DATE BILLED: 03/20/07 DATE DUE: 03/30/07
SERVICE ADDRESS:
SERVICE TYPE: RESIDENTIAL HEATING

PREVIOUS BALANCE		428.68
PAYMENT(S) RECEIVED - THANK YOU		194.08 CR
PREVIOUS BALANCE CARRIED FORWARD		234.60
CURRENT CHARGES		
SERVICE AND DELIVERY	9.38	
GAS COSTS: 22 THERMS @ $1.1074/TH	24.36	
SALES TAX	2.02	
TOTAL CURRENT CHARGES		35.76

AMOUNT DUE BY 03/30/07 $ 270.36

FINAL BILL

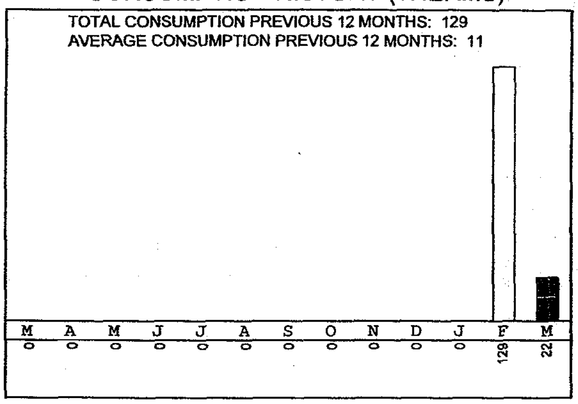
CONSUMPTION INFORMATION

PREVIOUS READ DATE	CURRENT READ DATE	DAYS OF SERVICE
02/28/07	03/13/07	13

PREVIOUS READING	CURRENT READING	GAS USED IN CCFS
925	946	21

GAS USED IN CCFS		MULTIPLIER		GAS USED IN THERMS
21	X	1.0250	=	22

CONSUMPTION HISTORY (THERMS)



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SULLIVAN, IN 47882-0187

OHIO VALLEY GAS
WWW.OVGC.COM

TELEPHONE (812) 268-6368
TOLL FREE 1-(877) 884-6368

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MONDAY – FRIDAY
7:00 A.M. – 4:00 P.M.

ONLY EMERGENCIES WILL BE RESPONDED TO AFTER 4:00 P.M.
TELEPHONE (812) 268-6369
TOLL FREE 1-(877) 884-6368

ADDITIONAL INFORMATION ON REVERSE

OVG OFFICE USE ONLY		
M ☐	Amt Received	$________
ND ☐	Amt Owed	$________
CK ☐	Change	$________

Complete this form only for new enrollments or changes.

DIRECT DEBIT PAYMENT PLAN ENROLLMENT (PRINT IN BLACK INK ONLY)

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Phone (Home)	Work	OVG Account Number (See Reverse)
Name on Financial Institution Account		Customer Name (See Reverse)
Routing Number (9 Digit)		Financial Institution Account Number
(ENCLOSE COPY OF VOIDED CHECK OR DEPOSIT SLIP)		
Signature		Date

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OHIO VALLEY GAS, INC
15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

ACCOUNT NUMBER	9-17-2206-9-2
DELINQUENT AMOUNT DUE BEFORE 04/02/07	**167.83**
	A

DISCONNECT NOTICE

000100**

SULLIVAN IN 47882-1222

OHIO VALLEY GAS, INC
P O BOX 187
SULLIVAN, IN 47882-0187

ALLOW 5 BUSINESS DAYS BY MAIL.

DETACH AND MAIL ENTIRE ABOVE PORTION WITH YOUR PAYMENT. PLEASE DO NOT FOLD, STAPLE OR CLIP PAYMENT TO BILL.

DISCONNECT NOTICE

ACCOUNT NUMBER: 9-17-2206-9-2

03/20/07

Your gas service at will be disconnected on or after 04/02/07 for non-payment of your delinquent balance of $167.83. To avoid disconnection of service, payment of the delinquent balance must be received by our office before 04/02/07. If a company representative is sent to your premises to collect the delinquent amount, you will also be subject to a $27.00 collection fee. If your service is disconnected for non-payment, a reconnection fee of $50.00 will be required in addition to payment of the delinquent balance before your service can be reconnected.

If you are unable to pay the delinquent balance before your disconnection date, please contact our office for possible payment arrangements. A partial payment will not ensure continuation of service unless a payment arrangement has been made with our office.

If you are subject to disconnection and are a residential customer, you may qualify for special **"Help Thy Neighbor Heating Fund"** assistance this year. Customers receiving, or eligible to receive, annual Energy Assistance Program (EAP) funding will not qualify for this special assistance. Please contact us **IMMEDIATELY** at the number below during our business hours with household income information to find out if you qualify.

Payment of your delinquent balance may now be made with an accepted credit or debit card. Call NCO Financial Systems, the card payment processing company, at 866-261-2990 to make payment; or contact our office for more details.

If you dispute the bill(s) in question or the scheduled disconnection, please contact our office during business hours before your disconnection date. A company representative will review the status of your account with you and the reason for the scheduled disconnection.

If payment has been made, please disregard this notice. This notice does not cancel any previous notice.

OHIO VALLEY GAS, INC
15 N STATE ST
P O BOX 187
SULLIVAN, IN 47882-0187

Telephone (812) 268-6368
Toll Free 1-(877) 884-6368
Business Hours:
Monday-Friday, 7:00a - 4:00p

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	)	CAUSE NO. 43208

PETITIONER'S EXHIBIT SMK

DIRECT TESTIMONY

OF

S. MARK KERNEY
VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

ON BEHALF OF

OHIO VALLEY GAS, INC.

MARCH 2007

PREPARED DIRECT TESTIMONY OF S. MARK KERNEY

OHIO VALLEY GAS, INC.

CAUSE NO. 43208

1. Q. Will you please state your name and business address?

A. S. Mark Kerney, 111 Energy Park Drive, Winchester, Indiana.

2. Q. By whom are you employed?

A. The Petitioner in this Cause No. 43208 - Ohio Valley Gas, Inc.

3. Q. What is your position with Petitioner?

A. Vice President and Chief Financial Officer.

4. Q. When did you begin your employment with the Petitioner?

A. On November 4, 2002.

5. Q. Will you please summarize your educational background?

A. I graduated from Indiana State University in 1976 with a Bachelor of Science degree in Accounting. Since 1982, I have been licensed as a Certified Public Accountant in Indiana in good standing. Additionally, I have attended numerous utility industry and professional seminars and courses during my career, including University of Michigan's comprehensive Utility Executive Program in 1987.

6. Q. Will you please state your employment history?

A. Upon graduation from Indiana State University, I was employed from 1976 to 1978 by the Evansville, Indiana office of Geo. S. Olive & Co, a certified public accounting firm headquartered in Indianapolis, performing client audit and tax return preparation assignments. In 1978, I joined Southern Indiana Gas & Electric Company (SIGECO), a NYSE-listed natural gas distribution and electric generation utility headquartered in Evansville. At SIGECO, I held various tax and financial accounting positions of increasing responsibility until 1989 when I was appointed Controller of SIGECO. In this role, I was responsible for the financial and regulatory accounting and reporting, taxes, budgets, customer billing and internal audit functions. These functions included the reconciliation of estimated to actual recoverable fuel costs for the quarterly GCA and FAC filings and related accounting issues, as well as various aspects of SIGECO's periodic general gas and electric rate case filings. In 1997, the utility holding company, SIGCORP, was formed to restructure SIGECO and a growing number of non-utility subsidiaries, and I was appointed Controller of SIGCORP, as well. In March 2000, SIGCORP and Indiana Energy, a utility holding company headquartered in Indianapolis, Indiana, merged to form the utility holding company, Vectren Corporation (Vectren), headquartered in Evansville. Appointed Director of Financial Accounting for Vectren effective with the merger, I was responsible for all aspects of financial and regulatory accounting and reporting, including SEC reporting for the new holding company and its operating utilities. In November 2002, I joined the Ohio Valley Gas Corporation as Chief Financial Officer, responsible for the financial and regulatory accounting and reporting, corporate taxes, treasury, gas supply, and customer billing functions of Ohio Valley Gas Corporation and its subsidiaries, including Ohio Valley Gas, Inc. Effective June 2005, I assumed the additional responsibility for the preparation, support and representation of the Petitioner's quarterly gas cost adjustment and general rate filings before this Commission. Effective November 1, 2005, I was appointed Vice President and Chief Financial Officer of Ohio Valley Gas Company and its subsidiaries, including Ohio Valley Gas, Inc.

7. Q. Are you a member of any business or professional organizations?

A. I am a member of the Gas Rate & Regulatory Committee of the Indiana Energy Association (IEA) and of the IEA Joint Customer Service Committee. Additionally, I am a member of the Indiana Association of Certified Public Accountants.

8. Q. Have you previously testified before the Indiana Utility Regulatory Commission ("IURC")?

A. I prepared and filed testimony for SIGECO addressing various accounting issues affecting the quarterly gas and fuel adjustment filings. Since June 2005, I have testified for the Petitioner in support of its quarterly GCA filings before this Commission.

9. Q. Is the Petitioner billing its customers and maintaining its records on an equivalent heating value basis?

A. Yes. All volumes expressed in this Cause are in their equivalent heating value on a "dry" British Thermal Unit ("BTU") basis versus "wet" basis for the historical twelve months ended June 30, 2006. Petitioner's interstate pipeline also operates on a dry BTU measurement basis. Likewise, all purchases of natural gas are made on a dry BTU measurement basis.

10. Q. Will you please identify and explain the documents marked as Petitioner's Exhibit SMK-1?

A. This is the Balance Sheet as of September 30, 2006 per Petitioner's books. Petitioner proposes a cut-off date of September 30, 2006 for determining original cost and fair value of Petitioner's utility properties.

11. Q. Will you please identify Petitioner's Exhibit SMK-2?

A. Page 1 is the Statement of Income for the twelve months ended June 30, 2006 per Petitioner's books. Pages 2 through 5 set forth additional details of the Statement of Income by service areas for the twelve months ended June 30, 2006. Petitioner proposes a test year of twelve months ended June 30, 2006.

12. Q. Will you please identify and explain the documents marked Petitioner's Exhibit SMK-3?

A. Exhibit SMK-3 is Petitioner's financial data, prepared in this Cause No. 43208 under my supervision, to support the need for an increase in the rates and charges Petitioner currently is authorized to charge its customers.

13. Q. Will you please explain Exhibit SMK-3, Pages 0 through 0B?

A. Page 0 through 0B is the Index of all Exhibit SMK-3 Pages.

14. Q. Will you please explain Exhibit SMK-3 Pages 1 through 1C?

A. Page 1 is the Adjusted Statement of Income for the twelve months ended June 30, 2006 reflecting adjustments for various fixed, known, and measurable changes to occur within twelve months following June 30, 2006. Pages 1A, 1B, and 1C summarize the year-end adjustments on a line-by-line basis with a reference to applicable Exhibit SMK-3 adjustment details.

15. Q. Will you please explain the purpose of Exhibit SMK-3, Pages 2 and 2A?

A. The purpose of this adjustment is to level and normalize the Gas Cost Adjustment (GCA) revenues for the test period. Page 2 shows the summary effect of restating the GCA calculation on an annual leveling and normalization basis using the adjusted cost of purchased gas (SMK-3, Page 5) and the test year actual revenues generated by the various GCA factors in effect during the test period. Page 2A is the GCA annual leveling and normalization calculation. There is no demand allocation since Petitioner pays no separately stated demand charges to its transportation provider (Texas Gas Transmission, LLC).

16. Q. Will you please explain Exhibit SMK-3, Pages 3 through 3C?

A. The Pages show the details of the calculation of the net change in unbilled revenues and comparison to the change per Petitioner's books, as well as the net change in unbilled sales volumes. The purpose of the unbilled sales and revenue adjustment is to remove the timing differences of Petitioner's various billing cycle months versus the calendar month used for purchasing natural gas supplies for the system.

17. Q. Will you please explain Exhibit SMK-3, Page 3D?

A. Page 3D details by month the test year proforma therms and revenues for Petitioner's transportation customer receiving service under Rate No. 96 compared to transportation revenues per Petitioner's books. No adjustment was required.

18. Q. Will you please explain Exhibit SMK-3, Page 4?

A. The purpose of this adjustment is to compensate for deviations from the 30-year normal temperatures as compiled by the NOAA. The total sales volumes for the three heating revenue classifications (residential, commercial, and public authorities) for the twelve months ending June 30, 2006, have each been adjusted for non-space heating volumes included therein. This was accomplished by assuming that all July, August, and September billing cycle sales for these customers were for non-space heating purposes, and then annualizing same. Historically, these three billing cycle months reflect the lowest three consecutive consumption months (June, July and August) of the year.

The normal and actual degree days used in the adjustment for all of Petitioner's customer service area are based on NOAA data for the Indianapolis International Airport Reporting Station. Petitioner used the most recent thirty-year average issued by NOAA which covers the period of 1971 through 2000 for the normal degree days.

The twelve-month period ending June 30, 2006 was approximately 11% warmer than the NOAA thirty-year average (thirty years ending 2000) for Petitioner's customer service area. Accordingly, Petitioner adjusted test year revenues upward to reflect the effect of twelve months of therm sales on a weather-normalized basis.

19. Q. Will you please explain Exhibit SMK-3, Page 4A?

A. Page 4A details the pro forma adjustment of the test year therms and revenues for Rate No. 91 (firm small volume) customers due to the decline in number of such customers for the twelve months following June 30, 2006, based on the percentage decline in number of such customers receiving service during January 2006 compared to January 2007. Petitioner has experienced a decline in the number of such customers each year for the past several years, and that decline continued past the test year.

20. Q. Will you please explain the purpose of Exhibit SMK-3, Page 5?

A. The purpose of this adjustment is to reflect the annualizing of purchased gas costs, including pipeline delivery service costs, and the impact of test year adjusted therm sales on purchased gas costs. Petitioner utilized applicable Federal Energy Regulatory Commission ("FERC") approved tariffs for pipeline cost calculations. The latest date of Texas Gas Transmission's (TGT) tariffs used is October 1, 2006. The commodity price used for the adjustment is the actual cost paid for natural gas delivered to Petitioner's system for the twelve months ended June 30, 2006. Regardless of the prices used to calculate this adjustment, Petitioner's customers will be charged what the gas cost adjustment ("GCA") mechanism dictates, not what Petitioner has included in this general rate filing. The amounts used in this Exhibit will generate the unit "base cost of gas" for the GCA mechanism used subsequent to the issuance of an order in this Cause.

All calculations are based on a dry BTU measurement basis to coincide with the billing mechanisms used by our interstate pipeline and natural gas supplier.

21. Q. Does Petitioner have a contract with Texas Gas Transmission, LLC (TGT) for transportation service?

A. Yes. Petitioner has a transportation contract with TGT for transport service with delivery points of:

At Riley, Indiana in Vigo County to serve the community of Riley and rural areas in Vigo, Indiana.

At Farmersburg, Indiana in Sullivan County to serve the communities of Curryville, Farmersburg and Shelburn, and rural areas of Sullivan County, Indiana.

At Hymera, Indiana in Sullivan County to serve the community of Hymera, and rural areas of Sullivan County, Indiana.

At Cass, Indiana in Sullivan County, Indiana to serve the communities of Cass, Dugger, New Lebanon, Sullivan and rural areas of Sullivan, Indiana.

At Petersburg, Indiana in Pike County, Indiana to serve the communities of Arthur, Ayrshire, Campbelltown, Winslow, and rural areas of Pike County, Indiana.

Check metering stations exist at Moyer Road and Riley Water Works in Vigo County, Indiana to serve customers adjacent to the TGT interstate pipeline in Vigo County, Indiana.

Check metering station exists at Blackhawk in Vigo County, Indiana to serve the community of Blackhawk and to serve customers adjacent to the TGT interstate pipeline.

Check metering station exists at White Rose in Greene County, Indiana to serve the White Rose Subdivision and to serve customers adjacent to the TGT interstate pipeline.

Numerous other individual taps exist along the TGT interstate pipeline and customers are served direct by individual metering in Greene, Knox, Pike, Sullivan and Vigo Counties, Indiana.

22. Q. What types of transportation agreements does Petitioner have with the interstate pipeline that transports natural gas to Petitioner's city gate stations and how is your natural gas supply arranged?

A. Petitioner has two Small General Transportation Service Agreements with TGT. Petitioner has a natural gas supply contract with BP Canada Energy Marketing, Inc. (BP) to provide all natural gas requirements. Petitioner's natural gas supply is purchased from BP under firm and index price arrangements. The majority of the purchases from BP are under (multiple) firm price arrangements between Petitioner and BP for delivery in future months, and pricing is driven by the NYMEX (New York Mercantile Exchange) at the time each contract is executed. The remaining gas supply is purchased under a two-fold index pricing arrangement. Natural gas nominated by Petitioner beyond the contractual obligations under the firm price arrangements is based on prices in the first monthly posting of the publication Inside F.E.R.C.'s Gas Marketing Report. Subsequent changes to the nominated quantities to be purchased under the monthly index price are priced at the daily price survey (midpoint) as shown in the publication Gas Daily for the balance of the calendar month. The firm-price arrangements are structured to result in multiple purchases for each month to enable "dollar-cost averaging" of the purchases, yet executed when Petitioner believes the prices are reasonable based on market conditions. Decisions to purchase gas are guided by an informal committee consisting of the General Manager, Chief Financial Officer and Gas Supply Director and resources used include, but are not limited, to Planalytics, Gas Daily, BTU's Daily Gas Wire, BP, and other industry resources.

23. Q. To what volumes of gas is Petitioner contractually entitled under its respective contracts?

A. Petitioner's agreement with TGT provides for transportation deliveries of 9,584 Dth of natural gas per day.

24. Q. Will you please explain Exhibit SMK-3, Page 6?

A. This adjustment reflects the application of payroll rates in effect on April 23, 2006 for the entire test period. It also calculates the applicable amount for operation and maintenance expense. The prorata General Office payroll expense amount applicable to Petitioner from its parent has been included in the adjustment.

25. Q. Will you please explain Exhibit SMK-3, Page 7?

A. This adjustment reflects the application of the Federal Insurance Contributions Act ("FICA") (includes both Medicare and social security) rates, State Unemployment Compensation ("ST UC") rates, and Federal Unemployment Tax Act ("FUTA") rates to the applicable payroll expense from Exhibit SMK-3, Page 6. The eligible wage bases applicable to these payroll taxes used in the various calculations are those in effect on January 1, 2007.

26. Q. Will you please explain Exhibit SMK-3, Page 8?

A. This adjustment reflects the decreased cost of liability and other insurance coverages compared to the costs incurred during the test year period. The premiums used for the adjustment are those paid by Petitioner for coverages in effect for the period July 1, 2006 through June 30, 2007.

27. Q. Will you please explain Exhibit SMK-3, Pages 9 through 9B?

A. This downward adjustment to postage expense reflects the decrease in postage costs resulting from annualizing the impact of Petitioner's implementation of the carrier route barcode address rate – the lowest available postage rate for its bills and related notices – during the test year period. The barcode rate used in the adjustment was the rate in effect at

January 1, 2007, and does not reflect the anticipated rate increase to $.312 per piece currently pending approval by the postal rate commission and Congress. Page 9 is the summary of the adjustment. Pages 9A and 9B are the details of the calculation of annualized cost applicable to the mailing of monthly utility bills for natural gas service, final utility bills to disconnected customers, shut-off notices to customers who fail to pay their bills by the due date, and Budget Plan notices.

28. Q. Will you please explain Exhibit SMK-3, Page 10?

A. This adjustment reflects the estimated cost of this rate case incremental to Petitioner's ongoing expenses. The rate case expense adjustment reflects the amortized expense of the outside professionals required by statute or by the Petitioner to accomplish this general rate increase proceeding. The outside professional services include legal counsel, expert witness testimony regarding the cost of equity capital, and expert witness testimony regarding cost of service study and rate design. Petitioner is requesting an amortization period of three (3) years for the rate case expenses. Also included are the costs of printing and mailing the required notices of the rate increase to Petitioner's customers (two mailings).

29. Q. Will you please explain exhibit SMK-3, Page 11?

A. This adjustment reflects the decreased cost of group insurance for Petitioner's full-time employees based on latest known premiums plus the cost of parent company General Office employees applicable to Petitioner. One-third of dependent coverage elected by the employee is paid by Petitioner and is included in the adjustment to the extent applicable to group insurance expense. The rates shown on Line 2 are the costs per insured per annum effective May 1, 2006, the most recent annual renewal period for those coverages, and such rates reflect increased cost-sharing by Petitioner's employees through increased employee deductible and co-insurance payment amounts, as well as lower claims experience. The rates shown on Line 9 are the costs per insured per annum effective January 1, 2005, the last time rates were established for these coverages. The rates on Line 16 are the costs per insured per annum effective May 1, 2006, the most recent annual renewal period for those coverages, as well.

The rates shown in columns (3), (4), and (5) are not the actual cost of the coverage but represent the portion of the total cost paid by Petitioner, equating to one-third of the total cost of the coverage. Petitioner pays the entire cost of the group term life insurance and it is applicable to all full-time employees. The life insurance plan provides reduced benefits for those employees over age 70. No dental, medical, or group term life insurance coverage for retired employees is provided, and no such cost is included in this adjustment.

30. Q. Will you please explain Exhibit SMK-3, Page 11A?

A. This adjustment reflects the scholarship awards granted in May 2006 for the 2006-2007 school year for employee dependents attending schools of higher learning. Only the portion applicable to Petitioner is included in the adjustment.

31. Q. Will you please explain Exhibit SMK-3, Pages 11B and 11C?

A. The adjustment reflects the decreased cost of worker's compensation insurance coverage based on the payroll included in Exhibit SMK-3, Page 6 and on insurance rates effective July 1, 2006. Page 11B is the detailed calculations and Page 11C shows the summary of the adjustment.

32. Q. Will you please explain Exhibit SMK-3, Page 12?

A. This adjustment reflects the change in Public Utility Fee due to the changes in gross revenues by the adjustments previously explained. The rate shown was the latest known rate at the time the Exhibit was prepared and was based on the billings due July 1, 2006 through April 1, 2007.

33. Q. Will you please explain Exhibit SMK-3, Page 13?

A. This adjustment reflects the changes in Indiana Utility Receipts Tax due to the changes in gross revenues by the adjustments previously explained. The adjustment was based on the rate of 1.4% which is the rate in effect at the time of this filing, for natural gas sales and transportation sales revenues.

34. Q. Will you please explain Exhibit SMK-3, Page 14?

A. This Page reflects the adjustment to book depreciation expense to annualize the depreciation expense for the changes in the Utility Plant in Service account during the test period. The adjustment is based on the depreciation rate of 3.0% which was approved by this Commission in Cause No. 32051 on January 23, 1970.

35. Q. Will you please explain Exhibit SMK-3, Page 14A?

A. This adjustment increases the annual depreciation expense on Petitioner's investment in Acct 391 - Office Equipment and Acct 397 - Communications Equipment by increasing the annual depreciation rate applied to this utility plant in service from 3.0% to 10.0% to reflect the much shorter lives of the technology investments contained in these plant accounts, than is reflected by the much lower historical depreciation rate.

36. Q. Will you please explain Exhibit SMK-3, Page 15?

A. This downward adjustment to test year property tax expense per books reflects the annualized expense based on the application of the latest known average tax rates to the March 1, 2006 assessment. The average tax rates were developed from payments made in May and September 2006.

37. Q. Will you please explain Exhibit SMK-3, Page 16?

A. This page reflects the adjustment to Indiana Adjusted Gross Income Tax due to the eligible adjustments explained on the previous pages of Exhibit SMK-3. The adjustment is calculated on the rate of 8.5%, the rate in effect at the time of this filing.

38. Q. Will you please explain Exhibit SMK-3, Page 17?

A. This page reflects the adjustment to Federal Income Tax due to the eligible adjustments explained on the previous pages of Exhibit SMK-3. This adjustment is calculated on the rate of 34%, the rate applicable to Petitioner.

39. Q. Will you please explain Exhibit SMK-3, Page 18?

A. This page details the calculations to support a change in Petitioner's current minimum reconnection charge of $50.00, to a new proposed minimum reconnection charge of $80.00. This charge is for the reconnection of service to the same customer at the same service address, and includes the cost of the disconnection as well as the reconnection. The increase in this charge is required because the actual cost to handle the reconnections as shown in the calculations is much greater than the current authorized charge.

40. Q. Will you please explain Exhibit SMK-3, Page 18A?

A. This page details the calculation of the various taxes and overhead charges used to determine the actual costs for reconnection charges, collection charges and returned check charges.

41. Q. Will you please explain Exhibit SMK-3, Page 19?

A. This page details the calculation to support a change in Petitioner's current collection charge of $27.00, to a proposed collection charge of $30.00. This charge covers the cost of making a collection trip to the premises of the customer for the purpose of collecting an unpaid natural gas bill or required customer security deposit. The increase in this collection charge is required because of the increased cost to make these collection trips to the customer's premises. Petitioner charges for a collection trip when it becomes necessary to send an employee or agent to the customer's premises to collect a specific unpaid natural gas bill or a customer security deposit. If multiple trips are required during any one billing cycle, only one such collection charge is assessed per billing cycle.

42. Q. Will you please explain Exhibit SMK-3, Page 20?

A. This page details the calculation to support a change in Petitioner's current returned check charge of $20.00, to a new proposed returned check charge of $21.00. This charge is to cover the cost of processing a returned check, including a direct debit to a customer's financial institution account, to Petitioner by Petitioner's financial institutions due to customer's insufficient funds. This proposed charge is less than the returned check charge currently in effect at many, if not most, commercial businesses in the areas Petitioner serves. The proposed applicable rate schedules also provide that any charges to Petitioner by its financial institutions will be added to the returned check charge and recovered from the applicable customer.

43. Q. Will you please explain Exhibit SMK-3, Page 21?

A. This Page shows the calculation of Petitioner's average investment in materials and operating supplies based on the thirteen months ended September 30, 2006, for use in determining the book value of total rate base.

There is no stored gas inventory for Petitioner. TGT retained title and control of all gas in storage at the commencement of FERC Order 636 on November 1, 1993. Petitioner must replace any gas withdrawn from TGT storage during any winter period, in the following summer period. The cost of natural gas in storage is carried in the rate base of TGT and not the Petitioner.

44. Q. Will you please explain Exhibit SMK-3, Page 22?

A. This page shows the summary of the lead/lag study calculation for required working capital for the twelve months ended June 30, 2006.

45. Q. Will you please explain Exhibit SMK-3, Pages 23 through 23B?

A. Page 23 is a summary of Petitioner's rate base components at September 30, 2006. The average inventory figure was computed on Exhibit SMK-3, Page 21 and the lead/lag calculation for working capital requirements was computed on Exhibit SMK-3, Page 22.

Page 23A shows the details of Utility Plant in Service at September 30, 2006 by functional plant and by FERC plant account number.

Page 23B details the calculation of the reserve for depreciation at September 30, 2006.

46. Q. Will you please explain Exhibit SMK-3, Page 24?

A. Page 24 sets forth the computation of the factors used to allocate the costs of Petitioner's General Office staff and operations and certain other administrative and general costs, such as liability insurance, as identified in various Pages of this Exhibit. The computation is based on the average ratios of net plant, operating revenues, volumes of gas sold and transported, and number of customers to totals for Petitioner and its subsidiary. The percentage allocation determined for Petitioner is 11.82%.

47. Q. Will you please explain Exhibit SMK-3, Page 25?

A. Page 25 sets forth the number of customers billed each month during the test period. The results on Line 17 are used for the "Customer" factor on Page 24, Line 13. Page 25 also reflects the pro forma adjustment to customer count for the decline in Rate No. 91 customers during the twelve months following June 30, 2006 (Exhibit SMK-3,Page 4A), included in the adjusted number of bills on Page 26.

48. Q. Will you please explain Exhibit SMK-3, Pages 26 through 26B?

A. Page 26 summarizes the adjusted test period bills and adjusted sales and transportation volumes for Petitioner by the rates in effect at the time of this filing.

Page 26A shows the calculation of adjusted test year sales and transportation volumes for the Petitioner, beginning with the actual test year volumes and adjusting for the weather normalization, unbilled sales, customer changes, etc. adjustments previously discussed.

Page 26B shows the calculation of adjusted sales revenue for Petitioner by rate for the test year beginning with actual test year sales revenues and adjusting for the various revenue adjustments previously discussed.

49. Q. Will you please explain Exhibit SMK-3, Page 27?

A. This Page details the calculation of the additional revenue resulting from the proposed changes to Petitioner's reconnection charge, collection charge, and returned check charge and the proposed additional revenue to be generated from gas sales and transportation sales.

50. Q. Will you please explain Exhibit SMK-3, Page 28?

A. This adjustment calculates the applicable taxes and public utility fee impact on the additional revenue required as determined on Page 30, Line 9.

51. Q. Will you please explain Exhibit SMK-3, Pages 29 through 29A?

A. Page 29 is the proposed Statement of Income for the twelve months ended June 30, 2006 reflecting the proposed additional revenue requirements and adjustments for applicable taxes and public utility fee.

Page 29A summarizes the adjustments for additional revenue required and the applicable taxes and public utility fee thereon on a line-by-line basis and reflected in Pages 29.

52. Q. Will you please explain Exhibit SMK-3, Pages 30 and 30A?

A. Page 30 details Petitioner's capitalization at September 30, 2006 and the calculation of the overall rate of return using an assigned return on equity of 11.75 percent. This Page sets forth the proposed utility operating income for Petitioner based on the 11.75 percent return on equity, and the required additional utility operating income necessary to achieve the proposed utility operating income. Lines 9 through 11 of Page 30 show the calculation of the additional revenue required to generate the proposed additional utility operating income, by applying a 1.6812 revenue conversion factor to the proposed utility operating income, and results in total proposed operating revenues.

Page 30A details the calculation of the1.6812 revenue conversion factor.

53. Q. Will you please explain Exhibit SMK-3, Page 31?

A. This Page sets forth the calculation of the amount (volumes) and percentage of unaccounted for gas to be included in base rates and provides the basis for the calculation of the base cost of gas applicable to unaccounted for gas for the GCA mechanism per Page 32. The average percentage of unaccounted for gas is based on the average of the results of five (5) twelve – month periods ending August 31, 2006, coinciding with such evaluation in Petitioner's GCA filings.

54. Q. Will you please explain Exhibit SMK-3, Page 32?

A. This Page sets forth the calculation of the base cost of gas to be used for the GCA mechanism following a Commission order in this proceeding, and will be updated if necessary to reflect the Commission's findings and final order in this Cause. The results shown are based on all applicable adjustments proposed in Exhibit SMK-3.

55. Q. Will you please explain Exhibit SMK-3, Pages 33 and 33A?

A. These Pages list by year the Net Income available to common shareholder (Parent) for the period 1950 through June 30, 2006 and the amount of common stock dividends paid during the same period. There is no established dividend payment schedule.

56. Q. Will you please explain Exhibit SMK-3, Pages 34 and 34A?

A. These Pages list by year the investment made by Petitioner in Utility Plant in Service from 1949 through June 30, 2006.

57. Q. Have you reviewed your operating revenues and operating expenses in connection with this Cause?

A. Yes. Petitioner has adjusted those operating revenues and operating expenses, where Petitioner has been able to determine that fixed, known, and measurable changes will occur during the twelve months following June 30, 2006, and will affect a particular operating revenue or operating expense. There are various expenses which are expected, or likely, to increase during the next twelve months (contracted services, wages and benefits, postage rates, utility bills, gasoline purchases, operating supplies and materials, etc) but they are not sufficiently fixed, known, and measurable for Petitioner to specifically identify or quantify. Additionally, no costs have been included in operating expenses for Petitioner's employee retirement income plan (Plan) for the test period, nor for many years preceding the test period, due to the funded status of the Plan.

58. Q. Does this conclude your direct testimony in the Cause?

A. Yes, it does.

OHIO VALLEY GAS, INC.

Balance Sheet at September 30, 2006

LN NO	(1) ASSETS AND OTHER DEBITS	(2)
	UTILITY PLANT	
1	Utility Plant in Service	$7,241,702
2	Less Accumulated Provision for Depreciation	5,035,974
3	**Net Utility Plant in Service**	$2,205,728
4	Construction Work in Progress	103,019
5	**Total Utility Plant**	$2,308,747
	CURRENT ASSETS AND ACCRUED ASSETS	
6	Cash	$477,163
7	Working Funds	1,450
8	Accounts Receivable	17,900
9	Other Accounts Receivable	184
10	Accumulated Provision for Uncollectible Accounts	(22,310)
11	Accounts Receivable from Associated Companies	2,419,968
12	Fuel Stock	562
13	Plant Materials and Operating Supplies	154,961
14	Stores Expense	22,556
15	Accrued Utility Revenue	70,948
16	**Total Current Assets**	$3,143,382
	DEFERRED DEBITS	
17	Miscellaneous Deferred Debits	$0
18	**TOTAL ASSETS**	$5,452,129

OHIO VALLEY GAS, INC.

Balance Sheet at September 30, 2006

LN NO	(1) SHAREHOLDERS' EQUITY AND LIABILITIES	(2)
	SHAREHOLDERS' EQUITY	
1	Common Stock Issued - No Par - No Stated Value	$4,000,000
2	Unappropriated Retained Earnings	346,363
3	**Total Shareholders' Equity**	$4,346,363
	CURRENT AND ACCRUED LIABILITIES	
4	Accounts Payable	$441,415
5	Accounts Payable to Associated Companies	124,882
6	Customer Deposits	458,511
7	Taxes Accrued	(248,340)
8	Interest Accrued	149,261
9	Tax Collections Payable	9,077
10	Miscellaneous Current and Accrued Liabilities	49,728
11	**Total Current and Accrued Liabilities**	$984,535
	DEFERRED CREDITS	
12	Customer Advances for Construction	$27,298
13	Other Deferred Credits	(359,403)
14	**Total Deferred Credits**	($332,105)
	CONTRIBUTIONS IN AID OF CONSTRUCTION	
15	Contributions in Aid of Construction	$116,329
	ACCUMULATED DEFERRED FEDERAL INCOME TAXES	
16	Accumulated Deferred Income Taxes	$337,006
17	**TOTAL SHAREHOLDERS' EQUITY AND LIABILITIES**	$5,452,129

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	OPERATING REVENUES	
1	Gas Sales	$6,323,801
2	Forfeited Discounts	26,054
3	Miscellaneous Operating Revenues	9,739
4	Transportation Revenues	11,270
4	**Total Operating Revenues**	$6,370,864
	OPERATING EXPENSES	
5	Purchased Gas	4,851,603
6	Transmission	47,189
7	Distribution	471,308
8	Customer Accounting	275,139
9	Administrative & General	541,421
10	Depreciation	202,609
11	Taxes - General	226,481
12	Taxes - Income - State	(8,162)
13	Taxes - Income - Federal	(52,568)
14	Provisions for Deferred Income Taxes	(28,067)
15	**Total Operating Expenses**	$6,526,953
16	**Utility Operating Income**	**($156,089)**
	OTHER INCOME	
17	Other Income - Net	$25,239
	INCOME DEDUCTIONS	
18	Other Interest	27,611
19	Miscellaneous Income Deductions	3,898
20	Allow for Funds Used During Construction	(2,637)
21	**Total Income Deductions**	$28,872
22	**NET INCOME**	($159,722)

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	GAS SALES	
1	Residential Non-Heating	$6,901.11
2	Residential Heating	4,207,374.08
3	Commercial Non-Heating	127,888.03
4	Commercial Heating	761,181.56
5	Industrial Firm	455,943.54
6	Public Authorities	731,602.98
7	Unbilled Revenue	32,910.00
8	**Total Gas Sales**	$6,323,801.30
	OTHER OPERATING REVENUES	
9	487 - Forfeited Discounts	$26,053.57
10	488 - Miscellaneous Service Revenues	9,739.44
11	489 - Transportation Revenues	11,269.52
12	**Total Other Operating Revenues**	$47,062.53
13	**Total Operating Revenues**	$6,370,863.83
	PURCHASED GAS	
14	804 - Purchased Gas	$5,226,216.85
15	805 - Amortization of Variances & Refunds	(374,613.37)
16	**Total Purchased Gas**	$4,851,603.48
	TRANSMISSION	
16	850 - Operation Supervision & Engineering	$0.00
17	856 - Mains Expense	17,711.39
18	857 - Measuring & Regulating Expense	4,195.17
19	859 - Other Expense	49.84
20	860 - Rent	100.00
20	**Total Transmission Operation Expense**	$22,056.40
21	861- Supervision & Engineering	$158.64
22	863 - Maintenance Mains	6,500.63
23	865 - Maintenance Measuring & Regulating Equipment	18,472.91
24	**Total Transmission Maintenance Expense**	$25,132.18
25	**Total Transmission Expense**	$47,188.58

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	DISTRIBUTION	
1	870 - Operation Supervision & Engineering	$122,601.01
2	874 - Main & Service Expense	38,649.26
3	875 - Measuring & Regulating Expense	354.34
4	878 - Meter & House Regulator Expense	85,405.81
5	879 - Customer Installation Expense	54,747.06
6	880 - Other Expense	57,484.99
7	881 - Rent	10.00
8	**Total Distribution Operation Expense**	$359,252.47
9	885 - Maintenance Supervision & Engineering	$14,772.89
10	886 - Maintenance of Structures	96.90
11	887 - Maintenance of Mains	22,797.21
12	889 - Maintenance Measuring & Regulating Equipment	15,891.96
13	890 - Maintenance Meas. & Reg. Equipment - Industrial	4,024.23
14	891 - Maintenance City Gate Stations	52.99
15	892 - Maintenance Services	10,966.27
16	893 - Maintenance Meter & Regulators	26,718.32
17	894 - Maintenance Other Equipment	16,734.62
18	**Total Distribution Maintenance Expense**	$112,055.39
19	**Total Distribution Expense**	$471,307.86
	CUSTOMER ACCOUNTING	
20	901 - Supervision	$49,161.22
21	902 - Meter Reading Expense	49,332.89
22	903 - Collection Expense	110,669.58
23	904 - Uncollectible Expense	5,468.57
24	905 - Miscellaneous Expense	14,747.36
25	907 - Billing Department Expense	45,759.83
26	**Total Customer Accounting**	$275,139.45
	SALES PROMOTION	
27	914 - Revenue - M&J Work	($15,244.97)
28	915 - Expense - M&J Work	11,724.81
29	**Total Sales Promotion**	($3,520.16)

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	ADMINISTRATIVE & GENERAL	
1	920.1 - Officers Salaries	$148,605.47
2	920.2 - General Office Salaries	44,720.94
3	921.1 - Officers Expenses	3,541.52
4	921.2 - General Office Expense	5,795.05
5	921.3 - General Office Supplies & Expense	18,453.12
6	923.1 - Outside Services	11,070.65
7	924.1 - Property Insurance Expense	0.00
8	925.1 - Liability Insurance Expense	35,507.28
9	925.2 - Worker's Compensation Cost	10,457.26
10	925.3 - Miscellaneous Insurance Expense	363.09
11	925.4 - Worker's Compensation Benefits	0.00
12	926.1 - Group Medical/Dental Insurance Expense	149,944.16
13	926.3 - Vacation Pay	47,438.21
14	926.4 - Holiday Pay	29,252.20
15	926.5 - Sick Pay	11,928.42
16	926.6 - Education Expense	8,631.20
17	926.7 - Employee Group Functions	4,618.76
18	926.8 - Employee Jury Duty Pay	154.90
19	926-9 - Fees for School, Etc.	1,025.75
20	930.1 - Miscellaneous General Expense	111.67
21	**Total Administrative & General Operation Expense**	$531,619.65
22	932.1 - Maintenance General Plant	$9,801.58
23	**Total Maintenance General Plant**	$9,801.58
24	**Total Administrative & General Maintenance Expense**	$541,421.23
25	**Total Operation and Maintenance Expense**	$6,183,140.44
	ACCOUNT 403 - DEPRECIATION EXPENSE	
26	403 - Depreciation Expense	$202,608.94
27	**Total Depreciation Expense**	$202,608.94

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(4) TOTAL COMPANY
	ACCOUNT 408 - TAXES - GENERAL	
1	408.1 - Real Estate & Personal Property Tax	$68,099.98
2	408.2 - Indiana Utility Receipt Tax	89,381.14
3	408.3 - Federal Insurance Contributions Act	58,213.66
4	408.4 - Federal Unemployment Tax	1,082.78
5	408.5 - State Unemployment Tax	2,649.95
6	408.6 - Public Utility Fee	6,328.62
7	408.9 - Miscellaneous Tax	724.49
8	**Total Taxes - General**	$226,480.62
	ACCOUNT 409 - TAXES - INCOME	
9	409-1 - Income Tax - Federal	($52,567.54)
10	409.2 - Income Tax - State	(8,162.03)
11	**Total Taxes - Income**	($60,729.57)
	ACCOUNT 410 - PROVISION FOR DEFERRED TAXES	
12	410.1 - Prov Def. Fed Inc. Tax - Depr	($22,376.74)
13	410.3 - Prov Def. Fed Inc. Tax - Bad Debts	(242.80)
14	410.5 - Prov Def. Fed Inc. Tax - Acc Vacation	(1,413.19)
15	410.2 - Prov Def. State Inc. Tax - Depr	(3,582.22)
16	410.4 - Prov Def. State Inc. Tax - Bad Debts	(66.34)
17	410.6 - Prov Def. State Inc. Tax - Acc Vacation	(386.10)
19	**Total Provision for Deferred Taxes**	($28,067.39)
	INTEREST INCOME	
20	419.1 - Interest Income - Taxable	$35,963.70
22	419.7 - State Income Tax Expense	(3,056.92)
23	419.8 - Federal Income Tax Expense	(11,188.31)
24	**Total Interest Income**	$21,718.47

OHIO VALLEY GAS, INC.

Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	MISCELLANEOUS OPERATING INCOME	
1	421.1 - Miscellaneous Nonoperating Income	$0.00
2	**Total Miscellaneous Operating Income**	$0.00
	ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION	
3	**420 - Allowance for Funds Used During Construction**	($2,636.94)
4	**Total Allowance for Funds Used During Construction**	($2,636.94)
	MISCELLANEOUS INCOME DEDUCTIONS	
5	426 - Miscellaneous Income Deductions	$3,896.70
6	**Total Miscellaneous Income Deductions**	$3,896.70
	OTHER INTEREST EXPENSE	
7	431.1 - Interest on Customer Deposits	$27,598.92
8	431.2 - Interest on Employee Stock Purchase Plan	12.48
9	**Total Interest Expense**	$27,611.40
10	**NET INCOME**	($159,721.90)

OHIO VALLEY GAS, INC.

OHIO VALLEY GAS, INC.

OHIO VALLEY GAS, INC.

OHIO VALLEY GAS, INC.

Adjusted Statement of Income for the Twelve Months Ended June 30, 2006

LN NO	(1)	(2) PER BOOKS AT 6-30-2006	(3) YEAR END ADJUSTMENTS	(4) ADJ. BASIS AT 6-30-2006
	OPERATING REVENUES			
1	Gas Sales	$6,323,801	$776,470	$7,100,271
2	Forfeited Discounts	26,054		26,054
3	Miscellaneous Operating Revenues	9,739		9,739
4	Transportation Revenues	11,270		11,270
5	**Total Operating Revenues**	**$6,370,864**	**$776,470**	**$7,147,333**
	OPERATING EXPENSES			
6	Purchased Gas	$4,851,603	805,113	$5,656,716
7	Transmission	47,189	414	47,603
8	Distribution	471,308	7,085	478,393
9	Customer Accounting	275,139	3,692	278,831
10	Administrative & General	541,421	(26,860)	514,561
11	Depreciation	202,609	14,066	216,675
12	Taxes - General	226,481	13,901	240,382
13	Taxes - Income - State	(8,162)	(3,083)	(11,245)
14	Taxes - Income - Federal	(52,568)	(12,759)	(65,327)
15	Provisions for Deferred Income Taxes	(28,067)		(28,067)
16	**Total Operating Expenses**	**$6,526,953**	**$801,569**	**$7,328,522**
17	**Utility Operating Income**	**($156,089)**	**($25,099)**	**($181,189)**

OHIO VALLEY GAS, INC.

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) DETAIL ADJUST
	OPERATING REVENUES		
	GAS SALES		
1	GCA Leveling & Normalization	2	$544,884
2	Weather Normalization	4	$319,278
3	Unbilled Revenues	3	($242)
4	Customer Decline Adjustment	4A	($87,450)
5	**Total Gas Sales Adjustments**		$776,470
6	**Total Operating Revenues**		$776,470
	OPERATING EXPENSES		
	PURCHASED GAS		
7	Purchased Gas Adjustment	5	$805,113
8	**Total Purchased Gas Adjustments**		$805,113
	TRANSMISSION		
9	Payroll Adjustment	6	$414
10	**Total Transmission Adjustments**		$414
	DISTRIBUTION		
11	Payroll Adjustment	6	$7,085
12	**Total Distribution Adjustments**		$7,085
	CUSTOMER ACCOUNTING		
13	Payroll Adjustment	6	$4,534
14	Postage Adjustment	9	(842)
15	**Total Customer Accounting Adjustments**		$3,692
	ADMINISTRATIVE & GENERAL		
16	Payroll Adjustment	6	$4,371
17	Group Insurance Adjustment	11	(38,789)
18	Scholarship Adjustment	11A	4,169
19	Worker's Compensation Adjustment	11C	2,816
20	Rate Case & Outside Professional Service	10	3,685
21	Liability Insurance Adjustment	8	(3,112)
22	**Total Administrative & General Adjustments**		($26,860)

OHIO VALLEY GAS, INC.

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) DETAIL ADJUST
	DEPRECIATION		
1	Depreciation Expense Adjustment	14	$2,485
2	Depreciation Rate Adjustment	14A	$11,581
3	**Total Depreciation Expense Adjustment**		$14,066
	TAXES - GENERAL		
4	FICA/State UC/FUTA Tax Adjustment	7	$5,653
5	Public Utility Fee Adjustment	12	1,218
6	Indiana Utility Receipts Tax Adjustment	13	10,871
7	Real Estate & Personal Property Tax Adjustment	15	(3,841)
8	**Total Taxes - General Adjustments**		$13,901
	TAXES - INCOME - STATE		
9	Indina Adjusted Gross Income Tax Adjustment	16	($3,083)
10	**Total Taxes - Income - State Adjustments**		($3,083)
	TAXES - INCOME - FEDERAL		
11	Federal Income Tax Adjustment	17	($12,759)
12	**Total Taxes - Income - Federal**		($12,759)
13	**Total Operating Expenses**		$801,569
14	**Net Effect on Utility Operating Income**		($25,099)

OHIO VALLEY GAS, INC.

Summary Of Year End Adjustments As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) DETAIL ADJUST
1	Total Operating Expense Applicable to Indiana Adjusted Gross Income Tax Calculation		$806,540
2	Total Operating Expense Applicable to Federal Income Tax Calculation		$814,328

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate For Leveling of GCA Factors And Normalization Of GCA Factors

LN NO	(1) MONTH	(2) TOTAL COMPANY
	GCA LEVELING ADJUSTMENT	
1	Annualized revenue from annualized GCA Factors (Page 2A, Line 12)	$2,432,572
	Revenues generated by various GCA factors for the twelve months ending June 30, 2006 (Line 7 of Schedule 6)	
2	July 2005	8,563
3	August	10,476
4	September	15,602
5	October	65,197
6	November	132,998
7	December	258,697
8	January 2006	400,348
9	February	437,017
10	March	341,445
11	April	102,221
12	May	73,475
13	June 2006	41,649
14	Totals for twelve months ended 6-30-06	$1,887,688
15	Year End Adjustment	$544,884

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues To Compensate
For Leveling Of GCA Factors

LN NO	(1)	(2) TOTAL COMPANY
1	Demand allocators from I.U.R.C. Cause No. 42240	0.00%
2	Adjusted cost of purchased gas (Pg. 5, L9)	$5,656,716
3	Cost of unaccounted for gas and Company use gas (Pg. 5, Line 4 plus Line 6 times Line 8)	$79,974
4	Demand cost in L2	$0
5	Commodity cost less cost of unaccounted for gas and Company use gas in L2	$5,576,742
6	Test year adjusted sales (Pg 26A, Line 10)	5,134,176
7	Non-allocated cost per Therm sales (L5/L6)	$1.0862
8	Demand cost per therm sales (L4/L6)	0.0000
9	Total cost of gas allocated (L7 +L8)	$1.0862
10	Less base cost of gas from I.U.R.C. Cause No. 42240	0.6124
11	Annualized GCA factor per therm (L9 - L10)	$0.4738
12	Annualized revenues from GCA factor (L6 X L11)	$2,432,572

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change
In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
1	Unbilled Revenues at June 30, 2006	$49,246
2	Unbilled Revenues at June 30, 2005	16,578
3	Increased Unbilled Revenues at June 30, 2006	$32,668
4	Less Unbilled Revenues as per books for the twelve months ended June 30, 2006	$32,910
5	Year End Adjustment	($242)
6	Add:Unbilled therms sales at June 30, 2006	40,455
7	Add: Unbilled therms sales at August 31, 2005	27,580
8	Less: Unbilled therms sales at June 30, 2005	19,584
9	Net change	48,451

10 All of Rates 92 and 93 are read and billed on a calendar month basis, and few Rate 94 sales occur in June.
11 Accordingly all unbilled sales and revenue at June 30 are assigned to Rate 91.

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	June 30, 2006	
1	Therm sales September 1, 2005 through June 30, 2006	4,602,038
2	Less Sept 2005 sales applic to Aug 2005 purchases	46,322
3	Therm sales September 1, 2005 through June 30, 2006	4,555,716
4	Therm purchases September 1, 2005 through June 30, 2006	4,631,070
5	Less unaccounted for gas and Company use gas	34,899
6	Net purchases for sales September 2005 through June 2006	4,596,171
7	Unbilled therm sales at June 30, 2006	40,455
8	June consumption rate	$1.2173
9	Unbilled revenue	$49,246

10 All of Rates 92 and 93 are read and billed on a calendar month basis, and few Rate 94 sales occur in June.

11 Accordingly all unbilled sales and revenue at June 30 are assigned to Rate 91.

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change
In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	August 31, 2005	
1	Therm sales September 1, 2004 through August 31, 2005	5,388,866
2	Less Sept 2004 sales applic to Aug 2004 purchases	49,036
3	Therm sales September 1, 2004 through June 30, 2005	5,339,830
4	Therm purchases September 1, 2004 through August 31, 2005	5,426,950
5	Less unaccounted for gas and Company use gas	59,540
6	Net purchases September 1, 2004 through June 30, 2005	5,367,410
7	Unbilled therm sales at August 31, 2005	27,580

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Revenues Due To Change In Unbilled Revenues At June 30, 2005 and June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	June 30, 2005	
1	Therm sales September 1, 2004 through June 30, 2005	5,219,116
2	Less Sept 2004 sales applic to Aug 2004 purchases	49,036
3	Therm sales September 1, 2004 through June 30, 2005	5,170,080
4	Therm purchases September 1, 2004 through June 30, 2005	5,246,710
5	Less unaccounted for gas and Company use gas	57,046
6	Net purchases September 1, 2004 through June 30, 2005	5,189,664
7	Unbilled therm sales at June 30, 2005	19,584
8	June consumption rate	$0.8465
9	Unbilled revenue	$16,578

10 All of Rates 92 and 93 are read and billed on a calendar month basis, and few Rate 94 sales occur in June.

11 Accordingly all unbilled sales and revenue at June 30 are assigned to Rate 91.

OHIO VALLEY GAS, INC

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Transport Customers For Twelve Months Ended June 30, 2006

	(1)	(2)	(3)	(4)
LN NO	MONTH	TOTAL BILLS	TOTAL THERMS	TOTAL REVENUE
	SULLIVAN CO HOSPITAL			
1	July 2005	1	7,153	$822
2	August	1	7,344	831
3	September	1	8,097	864
4	October	1	10,488	972
5	November	1	11,340	1,010
6	December	1	14,223	1,140
7	January 2006	1	12,158	1,047
8	February	1	11,800	1,031
9	March	1	11,777	1,030
10	April	1	8,362	876
11	May	1	8,230	871
12	June 2006	1	6,128	776
13	Totals	12	117,100	$11,270
14	Less transport revenue as per books for the twelve months ended 6-30-06			11,270
15	Year end adjustment			$0

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Revenues And Expenses
Due To Weather Normalization

LN NO	(1)	(2) TOTAL COMPANY
1	Total therm sales in heat sensitive classes for the twelve months ended June 30, 2006	4,203,855
2	Less Non-heat sensitive therm sales for July, August, and September billing cycles annualized	782,932
3	Heat sensitive therm sales (Line 1 less Line 2)	3,420,923
4	Base rate per therm	$0.7830
5	Degree days for twelve months ended June 30, 2006	4,933
6	NOAA 30-year average (1971-2000)	5,521
7	Percent of normal	89.3498%
8	Change to therm sales due to weather normalization (L3 divided L7 less L3)	407,763
9	Change in operating revenues (Line 4 times Line 8)	$319,278
10	Temperatures were warmer than normal.	
11	All change is applicable to Rate 91.	

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Revenues And Expenses
Due To Customer Decline

LN NO	(1)	(2) TOTAL COMPANY
1	Rate 91customers billed during January 2007	4,601
2	Rate 91 customers billed during January 2006	4,692
3	Decrease	(91)
4	Percentage decrease in Rate 91 customers	-1.94%
5	Rate 91customers billed July 1, 2005 through June 30 ,2006 (Pg 25, L 13)	55,452
6	Annualized Rate 91 customer billings adjustment (L 4 times L 5)	(1,076)
7	Monthly service charge - Rate 91	$13.00
8	Decrease in Rate 91 service charge revenue (L 6 times L 7)	($13,985)
9	Rate 91 therm sales per books (P 26A, L 1)	4,380,138
10	Rate 91 therm adjustment for weather normalization (P 26A, L 1)	407,763
11	Rate 91 therm adjustment for unbilled sales (P 26A, L 1)	48,451
12	Total Rate 91 therm sales subject to adjustment	4,836,352
13	Decrease in Rate 91 therm sales due to customer decline (L 12 times L 4)	(93,825)
14	Base Rate 91 per therm (P 4,L4)	$0.7830
15	Revenue per therm	$0.7830
16	Decr in Rate 91 sales revenue due to annualized customer decline (L 13 X L 16)	($73,465)
17	Total decrease in Rate 91 revenue due to customer decline (L 8 plus L 17)	($87,450)

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Expenses Due To
Annualizing Current Purchased Gas Rates

LN NO	(1) TEXAS GAS - ZONE 3	(2) TOTAL COMPANY
	Commodity Dth Calculation	
1	Rate 91 adjusted test period therm sales	4,742,527
2	Rate 93 adjusted test period therm sales	293,870
3	Rate 94 adjusted test period therm sales	97,779
4	Company use, etc.	28,901
5	Sub-total	5,163,077
6	Unaccounted for gas [Line 5 divided by (1 less Page 30, Line 22) less Line 5]	44,726
7	Adjusted Test Year Purchases	5,207,803
8	Average commodity cost delivered to city gate station for twelve months ended June 30, 2006	$1.0862
9	Total commodity cost - Zone 3 (Line 7 times Line 8)	$5,656,716
10	Less cost as per books for the twelve months ended June 30, 2006	4,851,603
11	Year End Adjustment	$805,113

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Expenses
Due To Changes In Payroll Rates

LN NO	(1)	(2)	(3) TOTAL COMPANY
1	Total annual payroll based on rates in effect April 23, 2006		$583,044
2	Portion applicable to operation and maintenance expense (92.15% times Line 1)		$537,275
3	INC. officer payroll		$81,887
4	General office allocation (4.95% times Corp. payroll)		$251,316
5	Portion of general office applic to operation and maintenance expense (100%)		$251,316
6	Total projected payroll cost (Sum of Lines 2, 3, and 5)		$870,478
7	Less payroll charged to operation and maintenance expense as per books for the twelve months ended June 30, 2006		853,905
8	Year End Adjustment		$16,573
	Allocation Of Year End Adjustment	**PERCENT**	**AMOUNT**
9	Transmission	2.50%	$414
10	Distribution	42.75%	7,085
11	Customer Accounting	27.36%	4,534
12	Sales Promotion	1.02%	169
13	General & Administrative	26.37%	4,371
14	Totals	100.00%	$16,573

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Expenses Due To Increased FICA/ST UC/FUTA Payroll Taxes Due To Increased Payroll And Tax Rate And Base Changes

LN NO	(1)	(2) SOCIAL SECURITY	(3) MEDICARE	(4) STATE UC	(5) FUTA
1	Total payroll subject to tax	$583,044	$583,044	$98,000	$98,000
2	Current rate	6.20%	1.45%	1.50%	0.80%
3	Tax (Line 1 times Line 2)	$36,149	$8,454	$1,470	$784
4	Total Tax (Sum of Line 3)				$46,857
5	Portion applicable to operations and maintenance expense (Line 4 times 92.15%)				$43,179
6	INC. Officers subject to tax	$51,173	$81,887	$0	$0
7	INC. Officers tax (L6 times L2)	$3,173	$1,187	$0	$0
8	Total INC. Officer Tax (Sum L7)				$4,360
9	General Office allocation subject to tax	$251,316	$251,316	$36,243	$36,243
10	General Office allocation tax (L9 * L2)	$15,582	$3,644	$544	$290
11	Total General Office Allocation Tax (Sum of Line 10)				$20,060
12	Portion applicable to operations and maintenance expense (Line 11 times 100%)				$20,060
13	Total Tax (Sum of Lines 5, 8, and 12)				$67,599
14	Less FICA/ST UC/FUTA payroll tax expense for the twelve months ended June 30, 2006				61,946
15	Year End Adjustment				$5,653

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Liability And Related Insurance Costs

LN NO	(1) CATEGORY	(2) TOTAL PREMIUM	(3) APPLICABLE OHIO VALLEY GAS CORP.	(4) APPLICABLE OHIO VALLEY GAS, INC.
1	Property Insurance Premium for the period July 1, 2006 through June 30, 2007:	$11,339	$9,999	$1,340
2	Commercial General Liability Insurance Premium for the period July 1, 2006 through June 30, 2007	79,649	70,234	9,415
3	Commercial Automobile Insurance Premium for the period July 1, 2006 through June 30, 2007	71,240	62,819	8,421
4	Umbrella Liability Insurance Premium for the period July 1, 2006 through June 30, 2007	100,775	88,863	11,912
5	Directors & Officers Liability Insurance Premium for the period February 12, 2006 through February 11, 2007	10,559	9,311	1,248
6	Dishonesty Bond for the period July 1, 2006 through June 30, 2007	500	441	59
7	Total Premiums (Sum of Lines 1 through 6)	$274,062	$241,667	$32,395

LN NO	CATEGORY	TOTAL PREMIUM
8	Property Insurance	$1,340
9	Commercial General Liability Insurance	9,415
10	Commercial Automobile Insurance	8,421
11	Umbrella Liability Insurance	11,912
12	D&O Liability Insurance	1,248
13	Dishonesty Bond Insurance	59
14	Total Premiums (Sum of Lines 8 thru 13)	$32,395
15	Less per books for twelve months ended June 30, 2006	35,507
16	Year End Adjustment	($3,112)

17 Allocations made on the basis of general spread.

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Summary Of Adjustment To Operating Expenses Due
To Postage Rates

LN NO	(1)	(2) TOTAL COMPANY
	Current Costs	
1	Utility bills	$16,050
2	Final bills	132
3	Shut Off Notices	1,573
4	Budget Plan Notices	426
5	Total Current Costs (Sum of Lines 1 through 4)	$18,181
6	Less postage costs as per books for the twelve months ended June 30, 2006	19,023
7	Year End Adjustment	($842)

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Postage Rates

LN NO	(1)	(2) TOTAL COMPANY
	Utility Bills	
1	Total customers billed for the twelve months ended June 30, 2006	54,777
	Utility Bill Mailings	
2	Mailed at barcode rate	54,777
3	Mailed at residual rate	0
4	Total (Line 2 plus Line 3)	54,777
	Utility Bill Mail Costs	
5	Barcode cost (Line 2 times $.293)	$16,050
6	Residual cost (Line 3 times $.39)	0
7	Total (Line 5 plus Line 6)	$16,050
	Final Bills	
8	Mailed at barcode rate	452
9	Mailed at residual rate	0
10	Total (Line 8 plus Line 9)	452
11	Barcode cost (Line 8 times $.293)	$132
12	Residual cost (Line 9 times $.39)	0
13	Total (Line 11 plus Line 12)	$132
	Shut-Off Notices, Etc.	
14	Mailed at barcode rate	5,368
15	Mailed at residual rate	0
16	Total (Line 14 plus Line 15)	5,368
17	Barcode cost (Line 14 times $.293)	$1,573
18	Residual cost (Line 15 times $.39)	0
19	Total (Line 17 plus Line 18)	$1,573

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Postage Rates

LN NO	(1)	(2) TOTAL COMPANY
	Budget Plan Notices, etc	
1	Mailed at barcode rate	1,453
2	Barcode cost (Line 1 times $.293)	$426
3	Total (Line 2)	$426
	Costs As Per Books For Twelve Months Ended June 30, 2006:	
4	Utility Bills	$16,770
5	Final Bills	132
6	Shut off Notices, Etc.	1,606
7	Budget Plan Notices	515
8	Total Costs As Per Books For Twelve Months Ended June 30, 2006	$19,023

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses For Rate Case Expense Due To The Employment Of Outside Professionals, Etc.

LN NO	(1)	(2) TOTAL COMPANY
1	Estimated legal expense	$4,728
2	Estimated cost of capital expert witness expense	4,137
3	Cost of printing required notices for rate increase	95
4	Cost of mailing required notices for rate increase	2,096
5	Total estimated rate case expense (Sum of Lines 1 thru 4)	$11,056
6	Cost applicable to next twelve months (Line 5 divided 3 years)	$3,685

7 Except L4, costs allocated on the basis of the gen expense allocation per Page 24, L 16.

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To
Increased Group Insurance Premium

LN NO	(1)	(2)	(3)	(4)	(5)
		TYPE OF COVERAGE			
	MEDICAL	EMPLOYEE	SPOUSE	CHILDREN	FAMILY
1	District Office lives	14	3	0	1
2	Rate per life (OVGI cost)	$5,252.28	$1,506.48	$1,030.56	$2,537.16
3	Cost (Line 1 times Line 2)	$73,532	$4,519	$0	$2,537
4	General Office lives	38	11	2	2
5	Cost (Line 4 times Line 2)	$199,587	$16,571	$2,061	$5,074
6	Appl. Petitioner (L5 * 11.82%)	$23,591	$1,959	$244	$600
7	Total Medical Cost (L3+L6)				$106,982
	DENTAL	EMPLOYEE	SINGLE DEP.	MULTIPLE DEP.	
8	District Office lives	14	5	3	
9	Rate per live	$210.12	$97.44	$194.88	
10	Cost (Line 8 times Line 9)	$2,942	$487	$585	
11	General Office lives	38	18	5	
12	Cost (line 9 times Line 11)	$7,985	$1,754	$974	
13	Appl. Petitioner (L12*11.82%)	$944	$207	$115	
14	Total Dental Cost (L10+L13)				$5,280
	LIFE		FULL	REDUCED 32.5k	REDUCED 25k
15	District Office lives		14	0	0
16	Rate per annum (OVGC cost)		$168.00	$151.32	$67.08
17	Cost (Line 15 times Line 16)		$2,352	$0	$0
18	General Office lives		39	1	1
19	Cost (Line 18 times Line 16)		$6,552	$151	$67
20	Appl. Petitioner (L19*11.82%)		$774	$18	$8
21	Total Life Cost (L17+L20)				$3,152
22	Total Group Insurance Cost				$115,414
23	Less group insurance cost capitalized (Line 22 times 3.69%)				4,259
24	Group insurance cost applicable to expense (Line 22 less Line 23)				$111,155
25	Less group insurance expense as per books for the twelve months ended 6-30-06				149,944
26	Year End Adjustment				($38,789)

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Operating Expenses Due To Scholarship Award
Changes In Number Of Participants And Level Of Benefit

LN NO	(1)	(2)	(3)	(4) TOTAL COMPANY
	Number of participants 2006-2007			
1	Applicable to Ohio Valley Gas, Inc.			4
2	Applicable to OVGC and OVGI (below)			0
3	Totals			4
4	Authorized award for 2006-2007 per participant			$3,200
5	Cost allocation			$12,800
6	Less cost as per books for the twelve months ended June 30, 2006			8,631
7	Year End Adjustment			$4,169

8	Applicable to OVGC and OVGI	1	
9	OVGC	1	per General Expense Allocation, p 24
10	OVGI	0	

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Worker's Compensation Insurance Due To Increased Payroll And Increased Rates

	(1)	(2)	(3)	(4)
LN		STATE OF COVERAGE		
NO	TOTAL COMPANY	INDIANA	NEBRASKA	TOTAL
1	Payroll basis - clerical	$208,926	$81,887	$290,813
2	- gas ops	367,983		367,983
3	Total	$576,909	$81,887	$658,796
4	Rate basis - clerical - per $100	$0.32	$0.42	
5	- gas ops - per $100	$1.72		
6	Worker's Compensation Costs			
7	Clerical	$669	$344	$1,013
8	Gas Ops	6,329		6,329
9	Sub-total (Line 7 plus Line 8)	$6,998	$344	$7,342
10	Waiver of Subrogation premium	$74	$0	$74
11	Subtotal (L 9 plus L10)	$7,072	$344	$7,416
12	Increased limits percentage	0.30%	0.30%	
13	Increased limits (L 11 times L12)	$21	$1	$22
14	Sub-total (Line 11 plus Line 13)	$7,093	$345	$7,438
15	Minimum premium adjustment	$0	$0	$0
16	Sub-total (Line 14 plus Line 15)	$7,093	$345	$7,438
17	Experience modification factor	135.00%	135.00%	
18	Adjusted premium (L16 X L17)	$9,576	$466	$10,042
19	Schedule Rating factor	-0.60%	-1.50%	
20	Schedule Rating adj L18 X L19)	($57)	($7)	($64)
21	Sub-total (Line 18 plus Line 20)	$9,519	$459	$9,978
22	Premium Discount factor	-4.43%	-7.90%	
23	Premium Discount (L 21 X L 22)	($422)	($36)	($458)
24	Subtotal (L 21 plus L 23)	$9,097	$423	$9,520
25	Expense constant	$0	$0	$0
26	Dom & For Ter (L3 X .0004)	$231	$33	$264
27	Sub-total (Line 24 plus Line 25 & 26)	$9,328	$455	$9,784
28	2nd injury fund surcharge	0.41%	0.00%	
29	2nd injury fund surcharge (L27 X L28)	$38	$0	$38
30	Sub-total (Line 27 plus Line 29)	$9,366	$455	$9,822
31	Total worker's compensation cost	$9,366	$455	$9,822

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Operating Expenses Due To Increased Worker's Compensation Insurance Due To Increased Payroll And Increased Rates

LN NO	(1)	(2) TOTAL
1	Total Worker's Compensation Cost (Page 11B, Line 31)	$9,822
2	Worker's Compensation Cost allocated from Ohio Valley Gas Corporation	3,451
3	Total Worker's Compensation Cost (Line 1 plus Line 2)	$13,273
4	Less Worker's Compensation Cost as per books the twelve months ended June 30, 2006	10,457
5	Year End Adjustment	$2,816

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Tax Expense Due To Public Utility Fee Computation On Revenue Changes

LN NO	(1)	(2) TOTAL COMPANY
1	Eligible revenue as per books for the twelve months ended June 30, 2006	$6,329,493
2	GCA leveling revenue adjustment	544,884
3	Unbilled revenue adjustment	(242)
4	Weather normalization adjustment	319,278
5	Customer decline adjustment	($87,450)
6	Adjusted Total Revenue (Sum Lines 1 to 5)	$7,105,962
7	Public Utility Fee (Line 6 times Line 10)	$7,547
8	Less Public Utility Fee as per books for the twelve months ended June 30, 2006	6,329
9	Year End Adjustment	$1,218
10	Latest annual available fee	0.106210%

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Tax Expense Due To Indiana Utility Receipts Tax Changes Due To Revenue Changes

LN NO	(1)	(2) TOTAL COMPANY
1	Eligible utility receipts per books for the twelve months ended June 30, 2006	$6,384,368
2	GCA leveling revenue adjustment	544,884
3	Unbilled revenue adjustment	(242)
4	Weather normalization adjustment	319,278
5	Customer decline adjustment	($87,450)
6	Adjusted Total Utility Receipts (Sum Lines 1 to 5)	$7,160,838
7	Utility Receipts Tax (Line 6 times Line 10)	$100,252
8	Less Utility Receipts Tax as per books for the twelve months ended June 30, 2006	89,381
9	Year End Adjustment	$10,871
10	Current effective rate	1.40%

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Depreciation Expense Due To Property Added During Base Period

LN NO	(1)	(2) TOTAL COMPANY
1	Total Utility Plant In Service at June 30, 2006	$7,241,702
	Less Non-Depreciable Property & Transportation Equipment	
2	Acct. 365.2 - Transmission Right of Ways	$7,769
3	Acct. 374 - Distribution Land and Land Rights	17,871
4	Acct. 389 - General Land and Land Rights	12,117
5	Acct. 392 - Transportation Equipment	367,471
6	Total Non-Depreciable Property	$405,229
7	Depreciable Utility Plant in Service at 6-30-06	$6,836,473
8	Depreciation Expense (Line 7 times Line 11)	$205,094
9	Less Depreciation Expense as per books for the twelve months ended June 30, 2006	202,609
10	Year End Adjustment	$2,485
11	Current approved depreciation rates as per IURC Cause No. 32051 approved January 23, 1970	3.00%

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Depreciation Expense Due To Increased Depreciation Rate On Certain Plant

LN NO	(1)	(2) TOTAL COMPANY
	Plant In Service June 30, 2006	
1	Acct 391 - Office Furniture & Equipment	$30,599
2	Acct 397 - Communications Equipment	134,843
		$165,442
3	Depreciation Expense at 10.0%	$16,544
4	Less: Depreciation Expense at 3.00% included on Pg 14	4,963
5	Depreciation Adjustment	$11,581

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details Of Adjustment To Tax Expense Due To Real Estate And Personal Property Tax Increase Due To Increased Assessment And Changes In Rates

	(1)	(2)
LN NO		TOTAL COMPANY
	Calculated assessment -2006 Payable 2007:	
	Real Estate	$192,500
	Personal Property	358,448
	State Board Distributable	1,900,190
	Special St Bd Distributable deduction@75%	(18,573)
1	Total	$2,432,565
2	Calculated average rate	$0.026416
3	Calculated property taxes (L1 times L2)	$64,259
4	Less Property Tax Expense as per books for the twelve months ended June 30, 2006	68,100
5	Year End Adjustment	($3,841)

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Income Tax Expense Due To Indiana Adjusted Gross Income Tax Changes Due to Revenue And Expense Changes

LN NO	(1)	(2) TOTAL COMPANY
1	Utility Operating Income as per books for the twelve months ended June 30, 2006	($156,089)
	ADD BACK:	
2	Depreciation - Book Basis	$202,609
3	Federal Income Tax	(52,568)
4	Deferred Fed & State Income Taxes	(28,067)
5	Indiana Adjusted Gross Income Tax	(8,162)
6	Indiana Utility Receipts Tax	89,381
7	Nondeductible meals expense (50%)	5,047
8	Total Add Back (Sum of Lines 2 through 7)	$208,240
9	Add Year End Adjustments to Operating Revenues	776,470
10	Less Year End Adjustments to Operating Expenses	806,540
11	Adjusted Total (L 1 plus L 8 plus L 9 less L 10)	$22,081
	LESS DEDUCTIONS:	
12	Depreciation - Tax Basis	$143,412
13	Net Deferred Timing Differences	(17,912)
14	Interest Expense	28,872
15	Total Deductions	$154,372
16	Income Subject to Adjusted Gross Income Tax (L 11 less L 15)	($132,291)
17	Indiana Adjusted Gross Income Tax (Line 16 X Line 20)	($11,245)
18	Less Indiana Adjusted Gross Income Tax as per books for the twelve months ended 6-30-06	(8,162)
19	Year End Adjustment	($3,083)
20	Current rate	8.50%

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Adjustment To Income Tax Expense Due To Federal Income Tax Changes Due To Revenue And Expense Changes

LN NO	(1)	(2) TOTAL COMPANY
1	Utility Operating Income as per books for the twelve months ended June 30, 2006	($156,089)
	ADD BACK:	
2	Depreciation - Book Basis	$202,609
3	Federal Income Tax	(52,568)
4	Deferred Federal Income Tax	(24,033)
5	Nondeductible meals expense (50%)	5,047
6	Total Add Back (Sum of Lines 2 through 5)	$131,055
7	Add Year End Adjustments to Operating Revenues	776,470
8	Less Year End Adjustments to Operating Expenses	814,328
9	Adjusted Total (L 1 plus L 6 plus L7 less L8)	($62,892)
	LESS DEDUCTIONS:	
10	Depreciation - Tax Basis	$118,285
11	Net Deferred Timing Differences	(17,912)
12	Interest Expense	28,872
13	Total Deductions	$129,245
14	Income Subject Federal Income Tax	($192,137)
15	Federal Income Tax (Line 14 times Line 18)	($65,327)
16	Less Federal Income Tax as per books for the twelve months ended June 30, 2006	(52,568)
17	Year End Adjustment	($12,759)
18	Current Rate	34.00%

OHIO VALLEY GAS, INC.

Details Of Calculation Of Reconnection Charge For Same Customers At Same Service Address

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing and disconnection paperwork including preparation of final bill (fraction of hour)	0.60
2	District Office processing of reconnection paperwork (fraction of hour)	0.60
3	District Office Time	1.20
4	Service Department processing of disconnection including travel time and paperwork (fraction of hour)	0.75
5	Service Department processing of reconnection including travel time and paperwork (fraction of hour)	0.85
6	Total Service Department Time	1.60
7	Billing Department process of final bill (fraction of hour)	0.10
8	District Office labor rate average	$13.90
9	Service Department labor rate average	$20.60
10	Billing Department labor rate average	$17.71
11	Fringes (Percent of labor) (Page 18A, Line 7)	23.83%
12	Payroll Tax (Percent of labor) (Page 18A, Line 3)	7.78%
13	Overheads including transportation costs (Percent of labor) (,Page 18A, Line 12)	36.80%
	Recap Of Cost	
14	District Office labor (Line 3 times Line 8)	$16.68
15	Service Department labor (Line 6 times Line 9)	32.96
16	Billing Department labor (Line 7 times Line 10)	1.77
17	Total Labor Charge (Sum of Lines 14 through 16)	$51.41
18	Fringes (Line 11 times Line 17)	12.25
19	Payroll tax (Line 12 times Line 17)	4.00
20	Overheads (Line 13 times Line 17)	18.92
21	Total Cost (Sum of Lines 17 through 20)	$86.58
22	Proposed Reconnection Charge	$80.00

OHIO VALLEY GAS, INC.

Details Of Calculation Of Various Taxes And Overhead
Charges For Reconnect, Trip Charge Fee, And Returned Check Charge

LN NO	(1)	(2) TOTAL COMPANY
	Computation Of Payroll Tax Rates:	
1	Total payroll (Page 1, Line 6 plus L3 and L4)	$916,247
2	Total FICA/ST UC/FUTA payroll tax (P7, Line 4 plus L8 and L11)	$71,277
3	Payroll Tax Percent (Line 2 divided by Line 1)	7.78%
	Computation Of Fringe Benefits:	
4	Account 926 - Employee Benefits as per books	$252,994
5	Year end adjustments	(34,620)
6	Total Fringe Benefits	$218,374
7	Fringe Benefits Percentage (Line 6 divided by Line 1)	23.83%
	Computation Of Administrative Overheads Less Fringes:	
8	Total Accounts 920 through 932 less Account 926 as per books	$288,428
9	Year end adjustments (Page 1, Line 10 less Line 5 above)	7,760
10	Total Administrative Overheads Less Fringes	$296,188
11	Applicable Operating Expenses (Page 1, Lines 7 through 9)	$804,827
12	Administrative Overheads (Line 10 divided by Line 11)	36.80%

OHIO VALLEY GAS, INC.

Details Of Calculation Of Collection Charge On Unpaid Accounts Requiring Visit To Premises

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing of paperwork (fraction of hour)	0.60
2	Service Department processing including travel time (fraction of hour)	0.55
3	Total District Office Time (Line 1 plus Line 2)	1.15
	Recap Of Cost:	
4	Office labor (Line 1 times Page 18, Line 8)	$8.34
5	Service Department labor (Line 2 times Page 18, Line 9)	11.33
6	Total Labor Charge	19.67
7	Fringes (Line 6 times Page 18A, Line 7)	4.69
8	Payroll tax (Line 6 times , Page 18A, Line 3)	1.53
9	Administrative overheads (Line 6 times Page 18A, Line 12)	7.24
10	Total Cost	33.13
11	Proposed Collection Charge	$30.00

OHIO VALLEY GAS, INC.

Details Of Calculation Of Returned Check Charge For Items Returned To Petitioner From Customers Financial Institution Not Paid

LN NO	(1)	(2) TOTAL COMPANY
1	District Office processing paperwork and telephone contact (fraction of hour)	0.90
	Recap Of Cost:	
2	Office labor (Line 1 times Page 18, Line 8)	$12.51
3	Fringes (Line 2 times Page 18A, Line 7)	2.98
4	Payroll tax (Line 2 times Page 18A, Line 3)	0.97
5	Administrative overheads (Line 2 times Page 18A, Line 12)	4.60
6	Total Cost	21.06
7	Proposed Returned Check Charge	$21.00

OHIO VALLEY GAS, INC.

Calculation Of Average Inventory For Use In Computing Rate Base At September 30, 2006

LN NO	(1) MONTH	(2) TOTAL COMPANY
1	September 2005	$139,275
2	October	137,300
3	November	137,913
4	December	137,447
5	January 2006	135,416
6	February	138,153
7	March	146,400
8	April	148,571
9	May	193,158
10	June	176,251
11	July	178,745
12	August	175,722
13	September 2006	178,078
14	Totals	$2,022,429
15	Average (Line 14 divided by 13)	$155,571

OHIO VALLEY GAS, INC.

Summary Of Lead/Lag Study For
The Twelve Months Ended June 30, 2006

LN NO	(1) DESCRIPTION	(2) EXPENSE AMOUNT	(3) EXPENSE LEAD(LAG)	(4) ** NET DAYS	(5) **** DAILY PERCENT	(6) REQUIREMENT PROVISION
1	Purchased Gas	$4,851,603	35.22	(0.13)	-0.04%	($1,941)
2	Payroll - Bi-weekly	772,018	10.00	25.09	6.87%	53,038
3	- Monthly	81,886	13.83	21.26	5.82%	4,766
4	General Insurance	46,328	(182.00)	217.09	59.48%	27,556
5	Other O&M Expenses	431,305	24.26	10.83	2.97%	12,810
6	Total O&M Expenses	$6,183,140				$96,229
	Tax Expense					
7	Indiana Property Tax	$68,100	376.50	(341.41)	-93.54%	(63,701)
8	Indiana Gross Receipts Tax	89,381	47.15	(12.06)	-3.30%	(2,950)
9	FICA Tax - Employer - Bi-weekly	55,081	13.00	22.09	6.05%	3,332
10	FICA Tax - Employer - Monthly	3,132	30.33	4.76	1.30%	41
11	FUTA Tax	1,083	75.13	(40.04)	-10.97%	(119)
12	State Unemployment Tax	2,650	75.14	(40.05)	-10.97%	(291)
13	IURC Fee	6,329	502.02	(466.93)	-127.93%	(8,097)
14	Federal Income Tax	(25,653)	(77.00)	112.09	30.71%	(7,878)
15	State Income Tax	8,295	42.00	(6.91)	-1.89%	(157)
16	Miscellaneous Tax	724	35.21	(0.12)	-0.03%	0
17	Total Tax Expense	$209,122				($79,820)
18	Total Cash Working Capital Requirement					$16,409
19	Revenue Lag (Days)	35.09				

20 ** Net days equals Revenue Lag less the Expense Lead(Lag).
21 ****Daily percent equals Net Days divided by 365.

OHIO VALLEY GAS, INC.

Rate Base Components As Per Books
At September 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
1	Utility Plant In Service	$7,317,964
2	Less Adjusted Accumulated Provision For Depreciation	5,028,030
3	Less Contributions In Aid Of Construction	116,329
4	Less Customer Advances For Construction	27,298
5	Net Utility Plant In Service	$2,146,308
6	Inventory	155,571
7	Working Capital	16,409
8	Total Rate Base	$2,318,288

OHIO VALLEY GAS, INC.

Details Of Utility Plant In Service
As Of September 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
	By Functional Plant	
1	Transmission	$1,655,466
2	Distribution	$4,464,668
3	General Plant	$1,197,831
4	Utility Plant In Service	$7,317,964
	By Plant Account	
	Transmission Plant	
5	Acct. 365.2 - Transmission Rights Of Way	$7,769
6	Acct. 367 - Transmission Mains	1,502,531
7	Acct. 369 - Transmission Measuring & Regulating Station Equipment	145,166
8	Total Transmission Plant	$1,655,466
	Distribution Plant	
9	Acct. 374 - Distribution Land And Land Rights	$18,006
10	Acct. 376 - Distribution Mains	2,952,326
11	Acct. 378 - Distribution Measuring & Regulating Station Equipment	36,936
12	Acct. 379 - Town Border Stations	98,878
13	Acct. 380 - Services	954,992
14	Acct. 381 - Meters	260,670
15	Acct. 383 - House Regulators	141,398
16	Acct. 385 - Industrial Measuring & Regulating Station Equipment	1,461
17	Total Distribution Plant	$4,464,668
	General Plant	
18	Acct. 389 - General Land And Land Rights	$12,117
19	Acct. 390 - General Structures And Improvements	272,965
20	Acct. 391 - Office Furniture & Equipment	30,599
21	Acct. 392 - Transportation Equipment	367,471
22	Acct. 394 - Tools & Work Equipment	378,816
23	Acct. 395 - Laboratory Equipment	397
24	Acct. 397 - Communications Equipment	134,843
25	Acct. 398 - Miscellaneous Equipment	623
26	Total General Plant	$1,197,831
27	Total Utility Plant In Service	$7,317,964
28	Plant in Service June 30, 2006	$7,241,702
29	Net Plant Placed in Service July 1-September 30, 2006	76,263
30	Total Plant in Service September 30, 2006	$7,317,965

OHIO VALLEY GAS, INC.

Details Of Accumulated Provision For Depreciation
As Of September 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
1	108.1 - Utility Plant In Service Accumulation Provision For Depreciation	$4,719,783
2	108.2-Transportation Reserve	320,098
3	Less: 108.2- Retirement Work in Progress	3,907
4	Total Accumulated Provision For Depreciation per books 9-30-06	5,035,974
5	Less: Plant Retirements July 1, 2006- September 30, 2006 not reflected in 108.2	4,022
6	Less: Cost of Removal incurred July 1, 2006 - September 30, 2006	3,923
7	Add: Salvage from Retirements July 1, 2006 -September 30, 2006	0
8	Adjusted Accumulated Provision For Depreciation at 9-30-06	$5,028,030

OHIO VALLEY GAS, INC.

Details Of Computation Of Factors Used For Allocation Of Certain Expenses Between Petitioner And Its Subsidiary Based on June 30, 2006 Data

LN NO	(1)	(2) TOTAL	(3) PARENT	(4) PETITIONER
	Utility Plant Factor			
1	Utility Plant in Service	$59,609,025	$52,367,323	$7,241,702
2	Less Depreciation Reserve	28,036,566	23,055,273	4,981,293
3	Net Utility Plant in Service	$31,572,459	$29,312,050	$2,260,409
4	Line 3 percent of total	100.00%	92.84%	7.16%
	Operating Revenues Factor			
5	Gas Sales - Net Billings	$43,041,212	$36,717,411	$6,323,801
6	Forfeited Discounts	164,692	138,638	26,054
7	Miscellaneous Service Revenues	121,948	112,209	9,739
8	Transportation Revenues	675,272	664,002	11,270
9	Total Operating Revenues	$44,003,124	$37,632,260	$6,370,864
10	Line 9 percent of total	100.00%	85.52%	14.48%
	Sales Volumes Factor (Dth)			
11	Total Dth Sales	5,059,100	4,565,366	493,734
12	Line 11 percent of total	100.00%	90.24%	9.76%
	Customers			
13	Average Customers at June 30, 2006	29,208	24,573	4,635
14	Line 13 percent of total	100.00%	84.13%	15.87%
15	Sum of Lines 4, 10, 12, and 14	400.00%	352.73%	47.27%
16	Line 15 percent of total	100.00%	88.18%	11.82%

OHIO VALLEY GAS, INC.

Details Of Customers Billed For The
Twelve Months Ended June 30, 2006

LN NO	(1) MONTH	(2) TOTAL COMPANY	(3) RATE NO. 91	(4) RATE NO. 93	(5) RATE NO. 94	(6) RATE NO. 96
1	July 2005	4,624	4,611	1	11	1
2	August	4,608	4,595	1	11	1
3	September	4,595	4,581	1	12	1
4	October	4,588	4,574	1	12	1
5	November	4,644	4,630	1	12	1
6	December	4,695	4,681	1	12	1
7	January 2006	4,706	4,692	1	12	1
8	February	4,698	4,684	1	12	1
9	March	4,693	4,679	1	12	1
10	April	4,646	4,632	1	12	1
11	May	4,588	4,574	1	12	1
12	June 2006	4,533	4,519	1	12	1
13	Total actual	55,618	55,452	12	142	12
14	Annualize Rate 94	2			2	
15	Rate 91 decline (Page 4A)	(1,076)	(1,076)			
16	Adjusted Total	54,544	54,376	12	144	12
17	Average Actual (L 13 div by 12)	4,635	4,621	1	12	1

OHIO VALLEY GAS, INC.

Adjusted Number of Bills and Therms By Rate
For The Twelve Months Ended June 30, 2006

LN NO	(1)	(2) NUMBER OF BILLS	(3) DEMAND/ ADJUSTED THERMS
	Rate No. 91		
1	Bills	54,376	
2	Therms		4,742,527
	Rate No. 92		
3	Bills	0	
4	Therms		0
	Rate No. 93		
5	Bills	12	
6	Therms		293,870
	Rate No. 94		
7	Service Charge Billed (annual) - Small	6	
8	Service Charge Billed (annual) - Large	6	
9	Therms		97,779
	Rate No. T95		
10	Bills	0	
11	Therms		0
	Rate No. T96		
12	Bills	12	
13	Therms		117,100
	Rate No. T98		
14	Bills- Meter Grp 1	0	
15	Bills- Meter Grp 2	0	
16	Bills- Meter Grp 3	0	
17	Therms-Meter Grp 1		0
18	Therms-Meter Grp 2		0
19	Therms-Meter Grp 3		0
20	Total	54,412	5,251,276

OHIO VALLEY GAS, INC.

Calculation Of Sales Therms By Rate For the Twelve Months Ended June 30, 2006 As Per Books Adjusted

LN NO	(1)	(2) ADJUSTED TOTAL THERMS	(3) AS PER BOOKS THERMS	(4) WEATHER NORMAL ADJUSTMENT	(5) UNBILLED REVENUE	(6) CUSTOMER COUNT CHANGE
1	Rate No. 91	4,742,527	4,380,138	407,763	48,451	(93,825)
2	Total Rate No. 91	4,742,527	4,380,138	407,763	48,451	(93,825)
3	Rate No. 92	0	0			
4	Total Rate No. 92	0	0	0	0	0
5	Monthly Demand Annualized	0				
6	Rate No. 93	293,870	293,870			
7	Total Rate No. 93	293,870	293,870	0	0	0
8	Rate No. 94	97,779	97,779			
9	Total Rate No. 94	97,779	97,779	0	0	0
10	Total Sales Therms	5,134,176	4,771,787	407,763	48,451	(93,825)
11	Rate No. T95	0	0			
12	Total Rate No. T95	0	0	0	0	0
13	Rate No. T96	117,100	117,100			
14	Total Rate No. T96	117,100	117,100	0	0	0
15	Total System Throughput	5,251,276	4,888,887	407,763	48,451	(93,825)

OHIO VALLEY GAS, INC.

Gas Sales Revenues Adjusted By Rates
For The Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL SERVICE AREA	(3) RATE 91	(4) RATE 93	(5) RATE 94
1	Total per billing register	$6,290,891	$5,900,182	$297,586	$93,123
2	GCA Leveling Adjustment	544,884	503,309	31,167	10,408
3	Unbilled Revenue at 6-30-05	(16,578)	(16,578)		
4	Unbilled Revenue at 6-30-06	49,246	49,246		
5	Weather Normalization Adjustment	319,278	319,278		
6	Customer Decline Adjustment	(87,450)	(87,450)		
7	Total	$7,100,271	$6,667,987	$328,753	$103,531
8	Adjusted Therm Sales	5,134,176	4,742,527	293,870	97,779
9	Percent of total	100.00%	92.37%	5.72%	1.91%

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details of Calculation Of Adjustment To Miscellaneous Service Revenues

LN NO	(1)	(2) TOTAL COMPANY
1	Reconnects during test year	103
2	Increase in proposed reconnection charge	$30
3	Proposed additional revenue	$3,090
4	Collection trips during test year	664
5	Increase in proposed collection trip charge	$3
6	Proposed additional revenue	$1,992
7	Returned checks during test year	97
8	Increase in proposed returned check charge	$1
9	Proposed additional revenue	$97
10	Total proposed additional revenue from miscellaneous service revenues	$5,179
11	Proposed increased revenue to be generated (Page 30, Line 9)	697,482
12	Proposed increased revenue to be generated from gas sales and transport ation (L11 less L10)	$692,303

OHIO VALLEY GAS, INC.

Details Of Year End Adjustments As Of June 30, 2006
Details of Effect on Certain Taxes and Fees Due To Proposed Increased Revenue

LN NO	(1)	(2) TOTAL COMPANY
1	Total proposed revenue (P 30, L11)	$7,844,815
2	Less adjusted revenue (P1, L5)	7,147,333
3	Increased revenue (Line 1 less Line 2)	$697,482
4	Increased utility receipts tax (Line 3 times Page 13, Line 10)	$9,765
5	Increased public utility fee (Line 3 times Page 12, Line 10)	741
6	Net (Line 3 less Line 4 and Line 5)	$686,976
7	Increased adjusted gross income tax (Line 6 times Page 16, Line 20)	$58,393
8	Net (Line 6 less Line 7)	$628,583
9	Increased Federal income tax (Line 8 times Page 17, Line 18)	$213,718
10	Increased Utility Operating Income (L8 less L9)	$414,865

OHIO VALLEY GAS, INC.

Proposed Statement Of Income For The Twelve Months Ended June 30, 2006

LN NO	(1)	(2) ADJUSTED BASIS 6-30-2006	(3) PROPOSED REV INCR EFFECT	(4) PROPOSED BASIS 6-30-2006
	Operating Revenues			
1	Gas Sales & Transportation Revenues	$7,111,540	$692,303	$7,803,843
2	Forfeited Discounts	26,054		26,054
3	Miscellaneous Service Revenues	9,739	5,179	14,918
4	Total Operating Revenues	$7,147,333	$697,482	$7,844,815
	Operating Expenses			
5	Purchased Gas	$5,656,716		$5,656,716
6	Transmission	47,603		47,603
7	Distribution	478,393		478,393
8	Customer Accounting	278,831		278,831
9	Administrative and General	514,561		514,561
10	Depreciation	216,675		216,675
11	Taxes - General	240,382	10,506	250,888
12	Taxes - Income - State	(11,245)	58,393	47,148
13	Taxes - Income - Federal	(65,327)	213,718	148,391
14	Provision Deferred Income Taxes	(28,067)		(28,067)
15	Total Operating Expenses	$7,328,522	$282,617	$7,611,139
16	Utility Operating Income	($181,189)	$414,865	$233,676

OHIO VALLEY GAS, INC.

Summary Of Adjustments On Proposed Revenue Increase As Of June 30, 2006

LN NO	(1)	(2) EXHIBIT SMK-3 PAGE NO.	(3) DETAIL ADJUSTMENT AMOUNT
	Gas Sales & Transportation		
1	Proposed revenue increase	27	$692,303
2	Total Gas Sales & Tranportation Revenues Adjustments		$692,303
	Miscellaneous Service Revenues		
3	Proposed rate effect on reconnect charges	27	$3,090
4	Proposed rate effect on collection charges	27	1,992
5	Proposed rate effect on returned checks charge	27	97
6	Total Miscellaneous Service Revenues Adjustments		$5,179
	Taxes - General		
7	Public Utility Fee adjustment	28	$741
8	Indiana Gross Receipts Tax adjustment	28	9,765
9	Total Taxes - General Adjustments		$10,506
	Taxes - Income - State		
10	Indiana Adjusted Gross Income Tax adjustment	28	$58,393
11	Total Taxes - Income - State Adjustments		$58,393
	Taxes - Income - Federal		
12	Federal Income Tax adjustment	28	$213,718
13	Total Taxes - Income - Federal Adjustments		$213,718
14	Net Effect On Utility Operating Income		$414,865

OHIO VALLEY GAS, INC.

Capitalization As Per Books At September 30, 2006
And Computed Overall Rate Of Return Based On Proposed Return On Equity

LN NO	(1)	(2) AMOUNT	(3) PERCENT OF TOTAL	(4) ASSIGNED COST	(5) RATE OF RETURN
	Equity				
1	Common Equity	4,346,363	82.14%	11.750%	9.65%
2	Customer Deposits	458,511	8.67%	5.000%	0.43%
3	Accr Interest on Cust Deposits	149,261	2.82%	0.000%	0.00%
4	Deferred Income Tax Reserve	337,006	6.37%	0.000%	0.00%
5	Totals	$5,291,143	100.00%		10.08%

Proposed Utility Operating Income

LN NO		
6	Total Utility Operating Income At Proposed Return On Equity	$233,683
7	Adjusted Utility Operating Income (Page 1, Line 17)	($181,189)
8	Additional Utility Operating Income (Line 6 less Line 7)	$414,872
9	Additional revenue required (Line 8 times Pg. 30A, Line 10)	$697,482
10	Adjusted Operating Revenues at 6-30-06 (Page 1, L5)	7,147,333
11	Total Proposed Operating Revenues	$7,844,815

OHIO VALLEY GAS, INC.

Computation Of Revenue Factor To Convert Additional Utility Operating Income To Additional Operating Revenue Requirements At June 30, 2006

LN NO	(1)	(2) AMOUNT
1	Gross Revenue Change	100.0000%
2	Less: Public Utility Fee (.1062097%)	0.1062%
3	Subtotal	99.8938%
4	Less: Indiana Utility Receipts Tax (at 1.40%)	1.3985%
5	Subtotal	98.4953%
6	Less: Indiana Adjusted Gross Income Tax (at 8.5%)	8.3721%
7	Subtotal	90.1232%
8	Less: Federal Income Tax (at 34%)	30.6419%
9	Change in In Net Operating Income	59.4813%
10	Revenue Conversion Factor	1.6812

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EXHIBIT - SMK-3
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OHIO VALLEY GAS, INC.

Unaccounted For Gas Percentage

LN NO	(1) Twelve Months Ended August 31,	(2) TOTAL COMPANY
	2006	
1	Gas Purchases - Dth	479,944
2	Gas Sold - Dth	478,136
3	Unaccounted For Gas	1,808
4	Percent Unaccounted For	0.38%
	2005	
5	Gas Purchases - Dth	542,695
6	Gas Sold - Dth	541,645
7	Unaccounted For Gas	1,050
8	Percent Unaccounted For	0.19%
	2004	
9	Gas Purchases - Dth	602,122
10	Gas Sold - Dth	595,833
11	Unaccounted For Gas	6,289
12	Percent Unaccounted For	1.04%
	2003	
13	Gas Purchases - Dth	663,150
14	Gas Sold - Dth	655,858
15	Unaccounted For Gas	7,292
16	Percent Unaccounted For	1.10%
	2002	
17	Gas Purchases - Dth	580,087
18	Gas Sold - Dth	570,922
19	Unaccounted For Gas	9,165
20	Percent Unaccounted For	1.58%
21	Five (5) Year Average UAF Percentage	0.86%
22	Per Schedule 11 and 11A, Gas Cost Adjustment filings	

OHIO VALLEY GAS, INC.

Details Of Calculation Of Base Cost Of Gas For The GCA Mechanism For The Twelve Months Ended June 30, 2006

LN NO	(1)	(2) TOTAL COMPANY
1	Base rate cost of gas (Page 5, Line 9)	$5,656,716
2	Less rate case cost allocated to rate schedules containing specific provision for adjustment for changes in gas cost	0
3	Less cost of unaccounted for gas (Page 5, Line 6 times Line 8)	48,582
4	Net base rate cost of gas (Line 1 less Lines 2 & 3)	$5,608,134
5	Total Dth sales (Page 26A, Line 10)	513,418
6	Less sales under rate schedules containing specific provision for adjustment for changes in gas cost	0
7	Net base rate Dth sales	513,418
8	Base rate cost of gas per Dth sales (Line 4 divided Line 7)	$10.923

OHIO VALLEY GAS, INC.

Analysis Of Net Income To Common And Dividends Paid January 1, 1960 Through June 30, 2006

LN NO	(1) YEAR	(2) NET INCOME TO COMMON	(3) DIVIDENDS PAID
1	1960	$5,148	
2	1961	19,989	
3	1962	8,428	
4	1963	5,292	
5	1964	(4,122)	
6	1965	21,243	
7	1966	24,700	
8	1967	30,645	
9	1968	(11,379)	
10	1969	1,984	
11	1970	111,714	
12	1971	82,894	
13	1972	107,942	
14	1973	136,413	
15	1974	135,885	
16	1975	166,710	
17	1976	139,495	
18	1977	128,227	
19	1978	143,500	
20	1979	152,343	
21	1980	54,752	
22	1981	91,014	
23	1982	190,127	
24	1983	247,131	
25	1984	528,354	
26	1985	161,991	
27	1986	204,390	1,990,000
28	1987	214,629	
29	1988	270,165	
30	1989	253,926	

OHIO VALLEY GAS, INC.

Analysis Of Net Income To Common
And Dividends Paid January 1, 1960 Through June 30, 2006

LN NO	(1) YEAR	(2) NET INCOME TO COMMON	(3) DIVIDENDS PAID
1	1990	$287,673	$1,000,000
2	1991	177,743	
3	1992	230,650	
4	1993	316,755	
5	1994	144,195	
6	1995	151,914	
7	1996	382,663	2,000,000
8	1997	247,460	
9	1998	136,382	
10	1999	129,345	1,000,000
11	2000	409,751	
12	2001	136,775	
13	2002	(95,176)	
14	2003	207,238	
15	2004	(101,864)	
16	2005	(114,558)	
17	6-30-2006	(57,234)	
18	Totals	$6,213,241	$5,990,000
19	Percent paid in dividends		96.41%

OHIO VALLEY GAS, INC.

Investment In Utility Plant In Service
During The Period January 1, 1960 Through June 30, 2006

LN NO	(1) YEAR	(2) INVESTMENT AMOUNT
1	1960	$27,596
2	1961	2,013
3	1962	944
4	1963	110,574
5	1964	388,476
6	1965	15,124
7	1966	25,858
8	1967	103,064
9	1968	41,656
10	1969	336,927
11	1970	673,872
12	1971	139,912
13	1972	211,832
14	1973	114,082
15	1974	108,685
16	1975	125,496
17	1976	95,340
18	1977	81,898
19	1978	161,971
20	1979	216,014
21	1980	163,936
22	1981	220,726
23	1982	154,534
24	1983	117,068
25	1984	162,692
26	1985	130,062
27	1986	196,296
28	1987	146,957
29	1988	190,133
30	1989	111,744

OHIO VALLEY GAS, INC.

Investment In Utility Plant In Service
During The Period January 1, 1960 Through June 30, 2006

LN NO	(1) YEAR	(2) INVESTMENT AMOUNT
1	1990	$196,948
2	1991	145,424
3	1992	162,236
4	1993	607,821
5	1994	197,607
6	1995	216,492
7	1996	70,645
8	1997	132,941
9	1998	125,424
10	1999	86,932
11	2000	95,729
12	2001	223,907
13	2002	998,462
14	2003	130,738
15	2004	321,047
16	2005	113,652
17	6-30-2006	144,884
18	Total	$8,546,370

BEFORE THE

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF OHIO VALLEY GAS, INC. FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	CAUSE NO. 43208
PETITION OF OHIO VALLEY GAS CORPORATION FOR (1) AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR GAS UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES AND CHANGES TO ITS GENERAL RULES AND REGULATIONS APPLICABLE TO GAS UTILITY SERVICE, INCLUDING CERTAIN INCREASES IN CERTAIN NON-RECURRING CHARGES; (3) AUTHORITY TO IMPLEMENT A NORMAL TEMPERATURE ADJUSTMENT MECHANISM AND DEFER THE NORMAL TEMPERATURE ADJUSTMENT MARGINS FOR FUTURE RECOVERY OR REFUND; (4) AUTHORITY TO IMPLEMENT A PIPELINE SAFETY COMPLIANCE COST TRACKING MECHANISM AND DEFERRAL ACCOUNTING OF SUCH COSTS UNTIL THE EFFECTIVE DATE OF THE TRACKING MECHANISM; (5) APPROVAL OF NEW DEPRECIATION RATES; AND (6) APPROVAL PURSUANT TO I.C. 8-1-2.5 OF SUCH ALTERNATIVE REGULATORY PLANS AS MAY BE REASONABLE, NECESSARY AND APPLICABLE TO SUCH AUTHORITY, APPROVALS AND DEFERRALS	CAUSE NO. 43209

PETITIONER'S EXHIBIT PRM
DIRECT TESTIMONY
OF
PAUL R. MOUL
ON BEHALF OF
OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.
MARCH 2007

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

Direct Testimony of Paul R. Moul

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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
g	Growth Rate
GCA	Gas Cost Adjustment
GDP	Gross Domestic Product
IURC	Indiana Utility Regulatory Commission
LDC's	Local Distribution Company
LT	Long Term
M&A	Merger and acquisition
MLP	Master Limited Partnerships
NTA	normal temperature adjustment
OVG	Ohio Valley Gas
PUHC	Public Utility Holding Company
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
v	represents the value that accrues to existing shareholders from selling stock at a price different from book value

OHIO VALLEY GAS CORPORATION

OHIO VALLEY GAS, INC.

CAUSE NO. 43208

CAUSE NO. 43209

Direct Testimony of Paul R. Moul

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

Q. Please state your name, occupation, and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant of the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience, and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis and a recommendation concerning the appropriate rate of return that the Indiana Utility Regulatory Commission ("IURC" or the "Commission") should allow Ohio Valley Gas Corporation and its subsidiary, Ohio Valley Gas, Inc., together referred to as "OVG" or the "Company," an opportunity to earn on its gas jurisdictional rate base devoted to public service. My analysis and recommendation are supported by the detailed financial data contained in Exhibit PRM-1, which is a multi-page document divided into eleven (11) schedules. Additional evidence, in the form of appendices, follows my direct testimony. The items covered in these appendices provide additional detailed information concerning the explanation and application of the various financial models upon which I rely.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return on common equity for the Company in this case?

A. My conclusion is that the Company should be afforded an opportunity to earn a rate of return on common equity within a range of 11.50% to 12.00%. From this range, I recommend an 11.75% rate of return on common equity for the purpose of this case. When applied to the Company's rate base, this rate of return will compensate investors for the use of their capital.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The majority of the Company's stock is owned by Beynon Farm Products Corporation. Lesser amounts of stock are owned by two individuals and the employee stock purchase plan. As such, the common stock of OVG is not traded. Therefore, it is necessary to measure the Company's cost of equity with market data obtained from a proxy group of companies.

The Company and its subsidiary provide natural gas distribution service to approximately 30,000 customers in rural areas of Indiana. Throughput to these customers in 2005 was represented by approximately 39% to residential customers, 12% to commercial customers, 43% to industrial and transportation customers and 5% to public authorities. Industrial and transportation customers consist of 214 customers, or less than one percent of the Company's customers. This means that the energy needs of a few customers can have a significant impact on the Company's operations. Also, approximately 97% of the Company's customers use natural gas for space heating purposes. This means that the Company's revenues are highly influenced by temperature conditions over which the Company has no control. For this reason, the Company is proposing a Normal Temperature Adjustment ("NTA") clause to its tariff.

The Company's flowing gas is provided by transportation arrangements with interstate pipelines. Texas Gas Transmission LLC and ANR Pipeline Company serve Ohio Valley Gas Corporation and Texas Gas Transmission, LLC serves Ohio Valley Gas, Inc. Ohio Valley Gas Corporation supplements its flowing gas supplies with propane.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a natural gas utility, such as OVG. In this regard, I relied on four well-recognized measures of the cost of equity: the Discounted

Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must provide a utility with the opportunity to cover its capital costs, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed, and support reasonable credit quality.

Q. What factors have you considered in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from my proxy group of seven natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey (either the basic or expanded issues), (iv) they have less than $1 billion of market capitalization of their equity, and (v) they are not currently the target of a merger or acquisition. The companies in the proxy group are identified on page 2 of Schedule 2. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not separately measured the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, any single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	9.87%
Risk Premium	11.69%
CAPM	9.58%
Comparable Earnings	15.55%
Average	11.67%
Median	10.78%
Mid-point	12.57%

From all these measures, the rate of return on common equity developed from the Gas Group is 11.67% using the average of all of these methods and 10.78% using the median of all of the methods. To accommodate the unique risk characteristics of OVG, I adjusted the results of the Gas Group. The two adjustments that I propose were intended to recognize the small size of OVG and the lack of long-term debt in the Company's capital structure. Those adjustments will be discussed later in my testimony.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. The new competitive, regulatory, and economic risks facing gas utilities are different today than formerly. Market-oriented pricing, open access for gas transportation, and changes in service agreements mean that natural gas utilities have been operating in a more complex environment with time frames for decision-making considerably shortened. Of particular concern for the Company, the recent high prices and volatility in natural gas commodity prices has had a negative impact on its customers. Higher commodity prices mean higher customer bills, as the cost of delivered gas is recovered through the GCA mechanism. Higher and volatile gas costs have resulted in further declines in average use per existing customer and in fewer new customers selecting natural gas to meet their energy needs. The resulting high gas prices have also had an impact on the amount of and number of delinquent customer accounts.

As the competitiveness of the natural gas business increases, the risk also increases. With the availability of customer-owned transportation gas, along with delivery of uncertain volumes to dual-fuel customers, risk will continue to rise as large end users obtain for themselves the range of unbundled service offerings which are currently available from the interstate pipelines for the local distribution utilities.

Q. Does the Company face competition in its natural gas business?

A. Yes. The changes fostered by the Federal Energy Regulatory Commission's Order 636 have promoted competition among and between pipelines and distributors through bypass facilities and placed more responsibilities on local distribution companies, such as OVG, to manage the upstream acquisition and delivery functions both from a reliability and price perspective. The major problem is that the larger customers have made their own gas supply arrangements and the customers that remain sales customers tend to be lower load factor customers that tend to be more expensive to serve.

Q. How does the Company's throughput to industrial customers affect its risk profile?

A. The Company's risk profile is strongly influenced by natural gas sold/delivered to industrial customers. Throughput to the Company's industrial and transportation customers represents 43% of total throughput. Indeed, the Company's ten largest customers (both sales and transportation service) together represent 29% of total throughput on the Company' system. Success in this aspect of the Company's market is subject to the business cycle, the price of alternative energy sources, and pressures from competitors. Moreover, external factors can also influence the Company's throughput to these customers which face competitive pressure on their operations from facilities located outside the Company's service territory. This risk is especially apparent for the Company where its largest customer, Visteon Auto Systems (a Ford Motor Company spin-off) located in

Connersville, Indiana, is scheduled to close its manufacturing plant in September, 2007.

Q. Please indicate how its construction program affects the Company's risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The Company projects its construction expenditures will be approximately $11.7 million in the period 2006-2010. Over this five-year period, these capital expenditures will represent approximately 38% ($11.7 million ÷ $30.9 million) of its net utility plant that was outstanding at December 31, 2005.

Q. Does your cost of equity analysis and recommendation take into account the NTA that is proposed by the Company in this case?

A. Yes. The Company proposes to include in its tariff, the NTA that is intended to adjust revenues for variations in year-to-year weather conditions from the "normal" weather assumed in establishing rates in the test year context. My cost of equity analysis that provides a range of 11.50% to 12.00% rate of return on common equity takes into account the Company's proposal.

Q. Do the LDCs included in your Gas Group already have tariff mechanisms similar to the NTA?

A. Yes, and therefore my analysis already reflects the impacts of the NTA on investor expectations through the use of market-determined models. Six of the companies in my Gas Group already have some form of revenue adjustment mechanism, related to temperature variations, and the one remaining company has a weather mitigation rate design intended to deal with the effect of weather volatility during the months of December through May. As such, the market prices of these companies' common equity reflect the expectations of investors related to a regulatory mechanism that adjusts revenues for abnormal weather.

Q. How do investors assess the risk to an LDC of variations in customer usage caused by weather?

A. Investors in a gas utility can only formulate reasonable expectations based upon normal weather, although achieved results may vary significantly from those expectations from year to year due to variations in weather. That is to say, a rational investor in a gas utility can only anticipate, and base his or her analyses on normal temperature conditions. The financial theory upon which the cost of equity is based recognizes that investors value their investments on a long-term basis covering a number of years, not just one year. For example, the DCF formula explicitly assumes a growth rate "approaching infinity." Additionally, as I will discuss later, analysts' forecasts of utilities' earnings and dividend growth, which investors take into account in making investment decisions, typically are provided on a five-year basis. Weather, by definition, is normal over the long-term or multi-year period, although it may vary significantly from year to year. Moreover, one of the standard models of the cost of equity (i.e., CAPM) suggests that there is no measurable effect on the cost of equity because weather represents a company-specific risk, which does not receive compensation in the CAPM. Therefore, the theories and models underlying my cost of capital analysis obviate the need for any adjustments based upon short-term phenomena such as weather variations which have no long-term effect. Accordingly, over the long term, the investor required cost of capital or discount rate assumed for an investment in a gas utility would be the same either with or without a NTA.

That is not to say there are no benefits to the proposed NTA. Variations in weather can significantly affect customers' bills and the Company's cash flow. Fluctuations in bad debt expense from year to year, which may also be driven in part by variations in weather, also affect the Company's cash flow. Therefore, the Company can be expected to realize a short-term benefit of improved or at least more predictable liquidity as a result of implementation of the NTA. Indeed, the NTA will remove some of the Company's cash flow variability.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular OVG?

A. The Commission should recognize and take into account the heightened competitive environment in the natural gas business in determining the cost of capital for the Company and provide a reasonable opportunity for the Company to actually achieve its cost of capital. This is especially important given the Company's small size and its significant exposure to the industrial class of customers.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors which bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and its required returns are described in Appendix C. For this purpose, I have utilized the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and the Gas Group.

Q. What are the components of the S&P public utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 3. I have used this group as a broad-based measure of all types of utility companies.

Q. What criteria did you employ to assemble the Gas Group?

A. The Gas Group that I employed in this case includes companies that are (i) engaged in similar business lines, (ii) have publicly-traded common stock, (iii) are included in <u>The Value Line Investment Survey</u> (either the basic or expanded issues), (iv) have less than $1 billion of market capitalization of their equity, and (vi) and they are not currently the target of a merger or acquisition. The Gas Group members are identified on page 2 of Schedule 2.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the credit rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Gas Group and the S&P Public Utilities?

A. Presently, the corporate credit rating ("CCR") for Gas Group is A- from Standard and Poor's Corporation ("S&P") and the Long Term ("LT") issuer rating is A3 from Moody's Investors Services ("Moody's"). Only three of the companies in the Gas Group have ratings from the bond rating agencies. It is not uncommon for small companies to have no credit rating on their debt, because much of their debt is obtained in the private placement market. The CCR designation by S&P and LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. For the S&P Public Utilities, the average composite rating is BBB+ by S&P and Baa1 by Moody's. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for OVG, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 1, 2 and 3. The data cover the five-year period 2001-2005. For the purpose of my analysis, I have analyzed the historical results for OVG, the Gas Group, and the S&P Public Utilities. I will highlight the important categories of relative risk as follows:

Size. In terms of capitalization, OVG is very much smaller than the average size of the Gas Group and the S&P Public Utilities. Indeed the Company's capitalization is about $30 million as compared to approximately $500 million for the Gas Group and approximately $15 billion for the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm will impact its cost of equity. This is the case for OVG. Indeed, the Company is only about one-seventh (1/17) of the average size of the Gas Group, which itself is represented by small companies. Such small size significantly elevates the Company's risk profile and increases its required return.

Market Ratios. Market-based financial ratios provide a partial indication of the investor-required cost of equity. If all other factors are equal, investors will require a higher return on equity for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[1]

There are no market ratios available for OVG because its stock is owned mostly by Beynon Farm Products Corporation. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was higher for the Gas Group, as compared to the S&P Public Utilities. The five-year average market-to-book ratio was fairly similar for the Gas Group and the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. OVG employs no long-term borrowed capital in its capitalization, and hence has no financial risk. The five-year average common equity ratios, based on permanent capital, were 100.0% for OVG, 49.7% for the Gas Group and 39.5% for the S&P Public Utilities.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 1.481 (4.0% ÷ 2.7%) for OVG, 0.064 (0.7% ÷ 10.9%) for the Gas Group, and 0.231 (2.5% ÷ 10.8%) for the S&P Public Utilities. The Company displays a high risk profile as revealed by very low earnings, which are highly variable as compared to the Gas Group and the S&P Public Utilities.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[2] The five-year average operating ratios were 96.5% for OVG, 87.2% for the Gas Group, and 84.6% for the S&P Public Utilities. The Company has very high operating risk as revealed by its high operating ratio.

[1] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

[2] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average interest coverage (excluding AFUDC) was 3.14 times for the Gas Group and 2.68 times for the S&P Public Utilities. Interest coverage multiples are not meaningful for the Company because it has no long-term debt outstanding.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of Allowance for Funds Used During Construction ("AFUDC") related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for OVG, the Gas Group, and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 141.7% for OVG, 82.3% for the Gas Group, and 109.0% for the S&P Public Utilities.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[3] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line betas provided on page 2 of Schedule 2 -- .64 as the average for the Gas Group, and page 3 of Schedule 3 -- .95 as the average for the S&P Public Utilities.

Q. Please summarize your risk evaluation of OVG and the Gas Group.

A. OVG is very much smaller than the average size of the Gas Group. The Company also possesses

[3] The procedure used to calculate the beta coefficient published by Value Line is described in Appendix H. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

higher operating risk than the Gas Group. As a mitigating risk factor, OVG lacks any financial risk because it has no long-term debt outstanding. The Company has historically experienced low and highly variable rates of return on common equity. In addition, the Company's customer base is dominated by a large proportion of sales to industrial and transportation customers, many of whom are engaged in manufacturing. Overall, the fundamental risk factors indicate that the Gas Group is useful in measuring the Company's cost of equity, when OVG-unique risk traits are taken into account.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships between OVG, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I describe in Appendix C. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As noted in Appendix C, and elsewhere in my direct testimony, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and have arrived at a range of the cost of equity of 11.50% to 12.00% for OVG.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The details of my use of the DCF approach and the calculations and evidence in support of my conclusions are set forth in Appendix D. I will summarize them here. The Discounted Cash Flow

("DCF") model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stocks consists of a current cash (dividend) yield and future price appreciation (growth) of the investment.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

As I describe in Appendix D, the DCF approach has other limitations that diminish its usefulness in the ratesetting process when the market capitalization diverges significantly from the book value capitalization. When this situation exists, the DCF method will lead to a misspecified cost of equity when it is applied to a book value capital structure.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended December 2006, the monthly dividend yields of the Gas Group are shown graphically on Schedule 4. The monthly dividend yields shown on Schedule 4 reflect an adjustment to the month-end prices to reflect the build up of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment). An explanation of this adjustment is provided in Appendix D.

For the twelve months ending December 2006, the average dividend yield was 3.88% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three- month periods were 3.81% and 3.76%, respectively. I have used, for the purpose of my direct testimony, a dividend yield of 3.81% for the Gas Group, which represents the six-month average yield. The use of this dividend yield will reflect current capital costs while avoiding spot yields.

For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments i.e., the higher expected dividends for the future.

Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different but generally accepted manners, and used the average of the three adjusted values as calculated in Appendix D. That adjusted dividend yield is 3.93% for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of its investment (i.e., the price per share of the stock). As I explain in Appendix D, future earnings per share growth represents its primary focus because under the constant price-earnings multiple assumption of the DCF model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth. The variables that can be considered include: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis can also be formulated, which consists of internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. The internal growth rate can be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time. Hence, a fundamental growth rate analysis is duplicative of expected book value per share growth.

Growth can also be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begins to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing its capital gains expectations with its dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. Therefore, in my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor expected growth.

Q. Before presenting your analysis of the growth rates that apply specifically to the Gas Group, can you provide an overview of the macroeconomic factors that influence investor growth expectations for common stocks?

A. Yes. As a preliminary matter, it is useful to view macroeconomic forecasts that influence stock prices. Forecast growth of the Gross Domestic Product ("GDP") can represent the starting point for this analysis. The GDP has both "product side" and "income side" components. The product side of the GDP is comprised of: (i) personal consumption expenditures; (ii) gross private domestic investment; (iii) net exports of goods and services; and (iv) government consumption expenditures and gross investment. On the income side of the GDP, the components are: (i) compensation of employees; (ii) proprietors' income; (iii) rental income; (iv) corporate profits; (v) net interest; (vi) business transfer payments; (vii) indirect business taxes; (viii) consumption of fixed capital; (ix) net receipts/payment to the rest of the world; and (x) statistical discrepancy. The "product side," (i.e., demand components) could be used as a long-term representation of revenue growth for public utilities. However, it is well known that revenue growth does not necessarily equal earnings growth. There is no basis to assume that the same growth rate would apply to revenues and all components of the cost of service, especially after the troublesome issues of employees' costs, insurance costs, high fuel costs, and environmental costs are worked-out in the long-term for public utilities. The earnings growth rates for utilities will be substantially affected by fluctuations in operating expenses and capital costs.

The long-term consensus forecast that is published semi-annually by the Blue Chip Economic Indicators ("Blue Chip") should be used as the source of macroeconomic growth. Blue Chip is a monthly publication that provides forecasts incorporating a wide variety of economic variables assembled from a panel of more than 50 noted economists from the banking, investment, industrial, and consulting sectors whose advice affects the investment activities of market participants. It is always preferable to use a consensus forecast taken from a large panel of contributors, rather than to rely upon one source that may not be representative of the types of information that have an impact on investor expectations. Indeed, Blue Chip is frequently quoted in The Wall Street Journal, The New York Times, Fortune, Forbes, and Business Week. Twice annually, Blue Chip provides long-range consensus forecasts. Based upon the October 10, 2006 issue of Blue Chip, those forecasts are:

Blue Chip Economic Indicators

Averages	Nominal GDP	Corporate Profits, Pretax
2008-12	5.2%	5.4%
2013-17	5.1%	5.8%

These forecasts show that growth in corporate profits generally will exceed growth in overall GDP. It also is indicated historically that the percentage change in corporate profits has been higher than the percentage change in GDP.[4]

Q. What company-specific data have you considered in your growth rate analysis?

A. I have considered the growth in the financial variables shown on Schedules 5 and 6. The bar graph provided on Schedule 5 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 5, historical

4 Obviously, growth in corporate profits is negatively impacted during recessionary periods, but on average corporate profits have grown historically over two percentage points faster than GDP since 1934.

growth in earnings per share was in the range of 4.00% to 4.93% for the Gas Group. Instances of negative growth reflected in the historical data provide no reliable guide to gauge investor expected growth for the future. Investor expectations encompass long-term positive growth rates and, as such, could not be represented by sustainable negative rates of change. Therefore, statistics that include negative growth rates should not be given any weight when formulating a composite growth rate expectation. The prospect of rate increases granted by regulators, the continued obligation to provide service as required by customers and the ongoing growth of customers mandate investor expectations of positive future growth rates. Stated simply, there is no reason for investors to expect that a utility will wind up its business and distribute its common equity capital to shareholders, which would be symptomatic of a long-term permanent earnings decline. Although investors have knowledge that negative growth and losses can occur, its expectations include positive growth. Negative historic values will not provide a reasonable representation of future growth expectations because, in the long run, investors will always expect positive growth. Indeed, rational investors expect positive returns, otherwise they will hold cash rather than invest with the expectation of a loss.

Schedule 6 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Zacks, and Reuters/Market Guide and from the Value Line publication. IBES/First Call, Zacks, and Reuters/Market Guide represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Zacks, and Reuters/Market Guide forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 6 for the Gas Group.

Although five-year forecasts usually receive the most attention in the growth analysis for DCF purposes, present market performance has been strongly influenced by short-term earnings forecasts. Each of the major publications provides earnings forecasts for the current and subsequent year. These short-term earnings forecasts receive prominent coverage, and indeed they dominate these publications. While the DCF model typically focuses upon long-run estimates of earnings, stock prices are clearly influenced by current and near-term earnings forecasts.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the DCF model?

A. Yes. In fact, it illustrates that the infinite form of the model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings (P-E) multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication signals that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What specific evidence have you considered in the DCF growth analysis?

A. As to the five-year forecast growth rates, Schedule 6 indicates that the projected earnings per share growth rates for the Gas Group are 5.74% by IBES/First Call, 4.92% by Zacks, 5.05% by Reuters/Market Guide, and 6.33% by Value Line. The Value Line projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 6.33%) than the dividends per share (i.e., 4.17%), which indicates a declining dividend payout ratio for the future. As indicated earlier, and in Appendix D, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data?

A. Although ideally historical and projected earnings per share and dividends per share growth indicators would be used to provide an assessment of investor growth expectations for a firm, the circumstances of the Gas Group mandate that the greater emphasis be placed upon projected earnings per share growth. The massive restructuring of the utility industry suggests that historical evidence alone does not represent a complete measure of growth for these companies. Rather, projections of future earnings growth provide the principal focus of investor expectations. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is forecasts of earnings per share growth. Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Reuters/Market Guide, and Value Line, represents a reasonable assessment of investor expectations.

It is appropriate to consider all forecasts of earnings growth rates that are available to investors. In this regard, I have considered the forecasts from IBES/First Call, Zacks, Reuters/Market Guide and Value Line. The IBES/First Call, Zacks, and Reuters/Market Guide growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks, and Reuters/Market Guide estimates are obtained from the Internet and are widely available to investors free-of-charge. First Call is probably quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries.

With the repeal of the 1935 Public Utility Holding Company ("PUHC") act, merger and acquisition ("M&A") activity, which already has been prevalent in the utility industry, is expected to accelerate. Acquisitions are usually accomplished at premiums offered to induce stockholders to sell its shares. These premiums create a ripple effect on the stock prices of all utilities, just like a rising tide lifts all boats. Due to M&A activity, there has been a run-up of the stock prices for some utility companies. With these elevated stock prices, dividend yields fall, and without some adjustment to the growth component of the DCF model, the results become unduly depressed by reference to alternative investment opportunities – such as public utility bonds. There are three remedies available to deal with these potentially anomalous DCF results: (i) an adjustment to the DCF model to reflect the divergence of market capitalization and the book value capitalization, (ii) the use of a growth component in the DCF model which is at the high end of the range, and (iii) supplementing the DCF results with other measures of the cost of equity.

The forecasts of earnings per share growth as shown on Schedule 6 provide a range of growth rates of 4.92% to 6.33%. To those company-specific growth rates, consideration must be given to long-term growth in corporate profits. While the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 5.75% is within the array of earnings per share growth rates shown by the analysts' forecasts and the forecast growth in overall corporate profits. The Value Line forecast of dividend per share growth is inadequate in this regard due to the forecast decline in the dividend payout that I previously described. As previously indicated, the restructuring and consolidation now taking place in the utility industry, will provide additional risks and opportunities as the utility industry successfully adapts to the new business environment. These changes in growth fundamentals will undoubtedly develop beyond the next five years typically considered in the analysts' forecasts that will enhance the growth prospects for the future. As such, a 5.75% growth rate will accommodate all these factors.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield and growth.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g ") previously developed. A flotation costs adjustment ("flot.") must be applied to the DCF result (i.e., "k") that provides an additional increment to the rate of return on equity (i.e., "K"). The factor used to develop the modification that would account for the flotation costs adjustment is provided in Schedule 7 and Appendix E. The resulting DCF cost rate is:

	D_1/P_0	+	g	=	k	x	*flot.*	=	K
Gas Group	3.93%	+	5.75%	=	9.68%	x	1.02	=	9.87%

As indicated by the DCF result shown above, the flotation cost adjustment adds 0.19% (9.87% - 9.68%) to the rate of return on common equity for the Gas Group. In my opinion, this adjustment is reasonable for reasons explained in Appendix E. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings multiples do not remain constant.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. The details of my use of the Risk Premium approach and the evidence in support of my conclusions are set forth in Appendix G. I will summarize them here. With this method, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 6.25% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds. As I will subsequently show, the Moody's index and the Blue Chip forecasts support this figure.

The historical yields for long-term public utility debt are shown graphically on page 1 of Schedule 8. For the twelve months ended December 2006, the average monthly yield on Moody's A-rated index of public utility bonds was 6.07%. For the six and three-month periods ending December 2006, the yields were 6.03% and 5.86%, respectively.

Q. What factors have influenced recent interest rates?

A. The low interest rates in 2003-'04 were, in part, the product of the Federal Open Market Committee ("FOMC") policy. In the two year period between June 2004 and June 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions, which have brought the Fed Funds rate to 5.25%, are widely interpreted as part of the process of moving toward a more neutral range for monetary policy. Current interest rates are characterized by a relatively flat to slightly inverted yield curve.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial

Forecasts ("Blue Chip") along with the spread in the yields that I describe above and in Appendix F. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2007, and the yield spread of 1.00% that I describe in Appendix F and Schedule 9. For comparative purposes, I have also shown the Blue Chip of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2007	First	5.5%	6.4%	4.8%	1.0%	5.8%
2007	Second	5.6%	6.5%	4.8%	1.0%	5.8%
2007	Third	5.7%	6.6%	4.9%	1.0%	5.9%
2007	Fourth	5.8%	6.7%	5.0%	1.0%	6.0%
2008	First	5.8%	6.7%	5.0%	1.0%	6.0%
2008	Second	5.9%	6.8%	5.1%	1.0%	6.1%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2006 publication, the Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts				
	Corporate		30-Year	A-rated Public Utility	
Averages	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2008-12	6.1%	7.0%	5.4%	1.0%	6.4%
2013-17	6.3%	7.1%	5.5%	1.0%	6.5%

Given these forecast interest rates, a 6.25% yield on A-rated public utility bonds represents a reasonable expectation.

Q. What equity risk premium have you determined for public utilities?

A. Appendix G provides a discussion of the financial returns that I relied upon to develop the appropriate equity risk premium for the S&P Public Utilities. I have calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds. I chose the S&P Public Utility index for the purpose of measuring the market returns for utility stocks. The S&P Public Utility index is reflective of the risk associated with regulated utilities than some broader market indexes, such as the S&P 500 Composite index. The S&P Public Utility index is a subset of the overall S&P 500 Composite index. Use of the S&P Public Utility index reduces the role of judgment in establishing the risk premium for public utilities. With the equity risk premiums developed for the S&P Public Utilities as a base, I derived the equity risk premium for the Gas Group.

Q. What equity risk premium for the S&P Public Utilities have you determined for this case?

A. To develop an appropriate risk premium, I analyzed the results for the S&P Public Utilities by averaging (i) the midpoint of the range shown by the geometric mean and median and (ii) the arithmetic mean. This procedure has been employed to provide a comprehensive way of measuring the central tendency of the historical returns. As shown by the values set forth on page 2 of Schedule 9, the indicated risk premiums for the various time periods analyzed are 5.37% (1928-2006), 6.40% (1952-2006), 5.61% (1974-2006), and 5.83% (1979-2005). The selection of the shorter periods taken from the entire historical series is designed to provide a risk premium that conforms more nearly to present investment fundamentals and removes some of the more distant data from the analysis.

Q. Do you have further support for the selection of the time periods used in your equity risk premium determination?

A. Yes. First, the terminal year of my analysis presented in Schedule 9 represents the returns realized through 2006. Second, the selection of the initial year of each period was based upon the events that I described in Appendix G. These events were fixed in history and cannot be manipulated as later financial data becomes available. That is to say, using the Treasury-Federal Reserve Accord as a defining event, the year 1952 is fixed as the beginning point for the measurement period regardless of the financial results that subsequently occurred. Likewise, 1974 represented a benchmark year because it followed the 1973 Arab Oil embargo. Also, the year 1979 was chosen because it began the deregulation of the financial markets. As such, additional data are merely added to the earlier results when they become available, clearly showing that the periods chosen were not driven by the desired results of the study.

Q. What conclusions have you drawn from these data?

A. Using the summary values provided on page 2 of Schedule 9, the 1928-2006 period provides the lowest indicated risk premium, while the 1952-2006 period provides the highest risk premium for the S&P Public Utilities. Within these bounds, a common equity risk premium of 5.72% (5.61% + 5.83% = 11.44% ÷ 2) is shown from data covering the periods 1974-2006 and 1979-2006. Therefore, 5.72% represents a reasonable risk premium for the S&P Public Utilities in this case. As noted earlier in my fundamental risk analysis, differences in risk characteristics must be taken into account when applying the results for the S&P Public Utilities to the Gas Group. I recognized these differences in the development of the equity risk premium in this case. I previously enumerated various differences in fundamentals between the Gas Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds, and betas. In my opinion, these differences indicate that 5.25% represents a reasonable common equity risk premium in this case. This represents approximately 92% (5.25% ÷ 5.72% = 0.92) of the risk premium of the S&P Public Utilities and is reflective of the risk of the Gas Group compared to the S&P Public Utilities.

Q. What common equity cost rate would be appropriate using this equity risk premium and the yield on long-term public utility debt?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). To that cost must be added an adjustment for common stock financing costs ("flot."). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*	+	*flot.*	=	*K*
Gas Group	6.25%	+	5.25%	=	11.50%	+	0.19%	=	11.69%

CAPITAL ASSET PRICING MODEL

Q. How have you used the Capital Asset Pricing Model to measure the cost of equity in this case?

A. I have used the Capital Asset Pricing Model ("CAPM") in addition to my other methods. As with other models of the cost of equity, the CAPM contains a variety of assumptions that I discuss in Appendix H. Therefore, this method should be used with other methods to measure the cost of equity, as each will complement the other and will provide a result that will alleviate the unavoidable shortcomings found in each method.

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. The details of my use of the CAPM and evidence in support of my conclusions are set forth in Appendix H. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities. As such, to calculate the CAPM it is necessary to employ firms with traded stocks. In this regard, I performed a CAPM calculation for the Gas Group. In contrast, my Risk Premium approach also considers industry- and company-specific factors because it is not limited to measuring just systematic risk. As a consequence, the Risk Premium approach is more comprehensive than the CAPM. In addition, the Risk Premium approach provides a better measure of the cost of equity because it is founded upon the yields on corporate bonds rather than Treasury bonds.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I considered the Value Line betas. As shown on page 1 of Schedule 10, the average beta is .64 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. For reasons explained in Appendix F, I have employed the yields on long-term Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratesetting process. As shown on pages 2 and 3 of Schedule 10, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2006, the average yield was 4.99%, as shown on page 3 of that schedule. For the six- and three-months ended December 2006, the yields on 20-year Treasury bonds were 4.96% and 4.83%, respectively. As shown on page 4 of Schedule 10, forecasts published by Blue Chip on January 1, 2007 indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.8% to 5.1% during the next six quarters. The longer term forecasts described previously show that the yields on Treasury bonds will average 5.4% from 2008 through 2012 and 5.5% from 2013 to 2017. For reasons explained previously, forecasts of interest rates should be emphasized at this time. Hence, I have used a 5.25% risk-free rate of return for CAPM purposes.

Q. What market premium have you used in the CAPM?

A. As developed in Appendix H, the market premium is developed by averaging historical market performance (i.e., 6.5%) and the forecasts (i.e., 6.44%). For the historically based market premium, I have used the arithmetic mean. I am aware that the Commission has expressed its preference for considering both the arithmetic mean and the geometric mean. So if that approach is to be taken, much more weight should be placed on the arithmetic mean because it is the correct measure in the single-period model specification of the CAPM. The resulting market premium is 6.47% (6.5% + 6.44% = 12.94% ÷ 2), which represents the average market premium using historical and forecast data.

Q. What CAPM result have you determined using the CAPM?

A. Using the 5.25% risk-free rate of return, the leverage adjusted beta of .64 for the Gas Group, the 6.47% market premium, and the flotation cost adjustment developed previously, the following result is indicated.

	Rf	+	ß	x (	Rm-Rf	) =	k	+	flot.	=	K
Gas Group	5.25%	+	0.64	x (	6.47%	) =	9.39%	+	0.19%	=	9.58%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The technical aspects of my Comparable Earnings approach are set forth in Appendix I. In order to identify the appropriate return on equity for a public utility, it is necessary to analyze returns experienced by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided. To avoid circularity, it is essential that returns achieved under regulation not provide the basis for a regulated return. Because regulated firms must compete with non-regulated firms in the capital markets, it is appropriate to view the returns experienced by firms which operate in competitive markets. One must keep in mind that the rates of return for non-regulated firms represent results on book value actually achieved, or expected to be achieved, because the starting point of the calculation is the actual experience of companies that are not subject to rate regulation. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.... The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

Therefore, it is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

There are two avenues available to implement the Comparable Earnings approach. One method would involve the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry would serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms. As such, this approach to Comparable Earnings avoids the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. Rather, it provides an indication of an earnings rate derived from non-regulated companies that are subject to competition in the marketplace and not rate regulation. Because, regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. This is because returns realized by non-regulated firms have become increasingly relevant with the current risk profile of the public utility business. Moreover, the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy.

To identify the comparable risk companies, the Value Line Investment Survey for Windows was used to screen for firms of comparable risks. The Value Line Investment Survey for Windows includes data on approximately 1700 firms. In the selection process, companies were excluded that are incorporated in foreign countries and are master limited partnerships (MLPs).

Q. How have you implemented the Comparable Earnings approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from the Value Line Investment Survey for Windows that have six categories (see Appendix I for definitions) of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The identities of companies comprising the Comparable Earnings group and its associated rankings within the ranges are identified on page 1 of Schedule 11.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 11 because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Finally, because many of the comparability factors, as well as the published returns, are used by investors for selecting stocks, and to the extent that investors rely on the Value Line service to gauge its returns, it is, therefore, an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecast returns for non-utility companies. As noted previously, I have not used returns for utility companies so as to avoid the circularity that arises from using regulatory influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (5 historical years and 5 projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization because the nature of the analysis relates to book value. Hence, Comparable Earnings does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. The historical rate of return on book common equity was 16.8% using the median value as shown on page 2 of Schedule 11. The forecast rates of return as published by Value Line are shown by the 14.3% median values also provided on page 2 of Schedule 11.

Q. What rate of return on common equity have you determined in this case using the Comparable Earnings approach?

A. The average of the historical and forecast median rates of return is:

	Historical	*Forecast*	*Average*
Group	16.80%	14.30%	15.55%

<u>CONCLUSION ON COST OF EQUITY</u>

Q. What is your conclusion concerning the cost of equity for the Gas Group?

A. Based upon the application of a variety of methods and models described previously, the cost of equity for the Gas Group is 11.67% using the average of all methods and 10.78% using the median of all methods. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations and infirmities that are inherent in each method. As I indicated previously, these results for the Gas Group require adjustment in this case for OVG.

Q. What adjustments to the Gas Group's results have you made for OVG?

A. I made two adjustments. The first adjustment relates to the issue of financial risk which is non-existent for the Company. The second adjustment relates to the Company's small size.

Q. How is the 11.67% and 10.78% cost of equity for the Gas Group adjusted for OVG's 100% common equity?

A. In pioneering work, Nobel laureates Modigliani and Miller developed several theories about the role of leverage in a firm's capital structure. As part of that work, Modigliani and Miller established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases. Likewise, the return on equity decreases when the financial leverage of a firm decreases. This principle is incorporated into the adjustment to the cost of equity for the Gas Group, and recognizes that the expected return on equity decreases when it is to be applied to 100% common equity.

Q. How can the Modigliani and Miller theory be applied to calculate the rate of return on common equity with 100% common equity?

A. First it is necessary to calculate the capital structure ratios for the Gas Group based upon the market value of their capitalization. By taking the "Fair Value of Financial Instruments" (Disclosures about Fair Value of Financial Instruments -- Statement of Financial Accounting Standards ("FAS") No. 107) shown in the annual report for these companies and the market value of the common equity using the price of stock, the capital structure ratios calculated from the market value of their securities are:

Capitalization at Market Value

Gas Group	(Fair Value)
Long-term Debt	34.37%
Preferred Stock	0.01
Common Equity	65.61
Total	100.00%

With the capital structure ratios shown above, the cost of equity for a firm without any leverage can be calculated. The cost of equity for an unleveraged firm using the average and median values for the Gas Group are shown below.

Average

$$ku = ke - (((ku - i)\ 1\text{-}t)\ D\ /\ E) - (ku - d)\ P\ /\ E$$

$$10.23\% = 11.67\% - (((10.23\%\text{-}6.03\%)\ .65)\ 34.37\%/65.61\%) - (10.23\% - 6.10\%)\ 0.01\%/65.61\%$$

Median

$$9.57\% = 10.78\% - (((9.57\%\text{-}6.03\%)\ .65)\ 34.37\%/65.61\%) - (9.57\% - 6.10\%)\ 0.01\%/65.61\%$$

where ku = cost of equity for an all-equity firm, ke = market determined cost equity, i = cost of debt , d = dividend rate on preferred stock, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The formula shown above indicates that the cost of equity for a firm with 100% equity is 10.23% and 9.57% using the market value of the Gas Group's capitalization.

Q. After adjustment for 100% common equity, would 10.23% and 9.57% rates of return on common equity be adequate for OVG?

A. No. As the size of a firm decreases, its risk, and hence its required return increases. In his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms (see <u>Fundamentals of Financial Management</u>, fifth edition, page 623). Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; <u>The Journal of Finance</u>, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in <u>Public Utility Fortnightly</u>, entitled "Equity and the Small-Stock Effect," by Michael Annin, it was demonstrated that the CAPM would understate the cost of equity significantly according to a company's size.

Q. How should the very small size of OVG be recognized in its equity return?

A. The 2006 SBBI Yearbook provides size premiums for mid-cap, low-cap, and micro-cap portfolios based upon returns in excess of the CAPM. The Gas Group has an average market capitalization of its equity of $430 million, which would place it in the ninth decile according to the size of the companies traded on the NYSE, AMEX and NASDAQ. Therefore, the Gas Group represents a micro-cap portfolio. OVG, however, has only $30 million of common equity which would place it in the smallest (i.e., the tenth) decile according to the 2006 SBBI Yearbook.

According to the 2006 SBBI Yearbook, the respective size premiums are 1.02% for mid-cap companies, 1.81% for low-cap companies, and 3.95% for micro-cap companies. The Company qualifies for the highest size adjustment attributed to companies in the micro-cap group. However, I have taken a conservative approach by adding just 1.81% to the Company's rate of return on common equity, corresponding to the more modest low-cap size premium. Hence, the rate of return on common equity that is related to 100% common equity would become 12.04% (10.23% + 1.81%) and 11.38% (9.57% + 1.81%), after adjustment for small size.

Q. Please summarize your recommendation concerning the appropriate rate of return on common equity for the Company.

A. Given the Company's risk traits enumerated earlier, its 100% common equity ratio, and its extremely small size, an 11.50% to 12.00% rate of return on common equity is reasonable for OVG. This return is based on the average and median results for the Gas Group after adjusting for financial risk and small size.

Q. Does this conclude your prepared direct testimony?

A. Yes.

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

CAUSE NO. 43208
CAUSE NO. 43209

Appendices A Through I to Accompany

the Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Concerning

Rate of Return

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past twenty-nine years, I have continuously studied the rate of return requirements for cost of service regulated firms. In this regard, I have supervised the preparation of rate of return studies which were employed in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty (30) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Oklahoma, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, and West Virginia; and the Philadelphia Gas Commission. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000).

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

I am a member of the Society of Utility and Regulatory Financial Analysis (formerly the National Society of Rate of Return Analysts) and have attended several Financial Forums sponsored by the Society. I attended the first National Regulatory Conference at the Marshall-Wythe School of Law, College of William and Mary. I also attended an Executive Seminar sponsored by the Colgate Darden Graduate Business School of the University of Virginia concerning Regulated Utility Cost of Equity and the Capital Asset Pricing Model. In October 1984, I attended a Standard & Poor's Seminar on the Approach to Municipal Utility Ratings, and in May 1985, I attended an S&P Seminar on Telecommunications Ratings.

My lecture and speaking engagements include:

Date	Occasion	Sponsor
April 2006	Thirty-eighth Financial Forum	Society of Utility & Regulatory Financial Analysts
April 2001	Thirty-third Financial Forum	Society of Utility & Regulatory Financial Analysts
December 2000	Pennsylvania Public Utility Law Conference: Non-traditional Players in the Water Industry	Pennsylvania Bar Institute
July 2000	EEI Member Workshop Developing Incentives Rates: Application and Problems	Edison Electric Institute
February 2000	The Sixth Annual FERC Briefing	Exnet and Bruder, Gentile & Marcoux, LLP
March 1994	Seventh Annual Proceeding	Electric Utility Business Environment Conf.
May 1993	Financial School	New England Gas Assoc.
April 1993	Twenty-Fifth Financial Forum	National Society of Rate of Return Analysts
June 1992	Rate and Charges Subcommittee Annual Conference	American Water Works Association
May 1992	Rates School	New England Gas Assoc.
October 1989	Seventeenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners Florida

		Public Service Commission and University of Utah
October 1988	Sixteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
May 1988	Twentieth Financial Forum	National Society of Rate of Return Analysts
October 1987	Fifteenth Annual Eastern Utility Rate Seminar	Water Committee of the National Association of Regulatory Utility Commissioners, Florida Public Service Commission and University of Utah
September 1987	Rate Committee Meeting	American Gas Association
May 1987	Pennsylvania Chapter annual meeting	National Association of Water Companies
October 1986	Eighteenth Financial Forum	National Society of Rate of Return
October 1984	Fifth National on Utility Ratemaking Fundamentals	American Bar Association
March 1984	Management Seminar	New York State Telephone Association
February 1983	The Cost of Capital Seminar	Temple University, School of Business Admin.
May 1982	A Seminar on Regulation and The Cost of Capital	New Mexico State University, Center for Business Research and Services
October 1979	Economics of Regulation	Brown University

EVALUATION OF RISK

The rate of return required by investors is directly linked to the perceived level of risk. The greater the risk of an investment, the higher is the required rate of return necessary to compensate for that risk all else being equal. Because investors will seek the highest rate of return available, considering the risk involved, the rate of return must at least equal the investor-required, market-determined cost of capital if public utilities are to attract the necessary investment capital on reasonable terms.

In the measurement of the cost of capital, it is necessary to assess the risk of a firm. The level of risk for a firm is often defined as the uncertainty of achieving expected performance, and is sometimes viewed as a probability distribution of possible outcomes. Hence, if the uncertainty of achieving an expected outcome is high, the risk is also high. As a consequence, high risk firms must offer investors higher returns than low risk firms which pay less to attract capital from investors. This is because the level of uncertainty, or risk of not realizing expected returns, establishes the compensation required by investors in the capital markets. Of course, the risk of a firm must also be considered in the context of its ability to actually experience adequate earnings which conform with a fair rate of return. Thus, if there is a high probability that a firm will not perform well due to fundamentally poor market conditions, investors will demand a higher return.

The investment risk of a firm is comprised of its business risk and financial risk. Business risk is all risk other than financial risk, and is sometimes defined as the staying power of the market demand for a firm's product or service and the resulting inherent uncertainty of realizing expected pre-tax returns on the firm's assets. Business risk encompasses all operating factors, e.g., productivity, competition, management ability, etc. that bear upon the expected pre-tax operating income attributed to the fundamental nature of a firm's business. Financial risk results from a firm's use of borrowed funds (or similar sources of capital with fixed payments) in its capital structure, i.e., financial leverage. Thus, if a firm did not employ financial leverage by borrowing any capital, its investment risk would be represented by its business risk.

It is important to note that in evaluating the risk of regulated companies, financial leverage cannot be considered in the same context as it is for non-regulated companies. Financial leverage has a different meaning for regulated firms than for non-regulated companies. For regulated public utilities, the cost of service formula gives the benefits of financial leverage to consumers in the form of lower revenue requirements. For non-regulated companies, all benefits of financial leverage are retained by the common stockholder. Although retaining none of the benefits, regulated firms bear the risk of financial leverage. Therefore, a regulated firm's rate of return on common equity must recognize the greater financial risk shown by the higher leverage typically employed by public utilities.

Although no single index or group of indices can precisely quantify the relative investment risk of a firm, financial analysts use a variety of indicators to assess that risk. For example, the creditworthiness of a firm is revealed by its bond ratings. If the stock is traded, the price-earnings multiple, dividend yield, and beta coefficients (a statistical measure of a stock's relative volatility to the rest of the market) provide some gauge of overall risk. Other indicators, which are reflective of business risk, include the variability of the rate of return on equity, which is indicative of the uncertainty of actually achieving the expected earnings; operating ratios (the percentage of revenues consumed by operating expenses, depreciation, and taxes other than income tax), which are indicative of profitability; the quality of earnings, which considers the degree to which earnings are the product of accounting principles or cost deferrals; and the level of internally generated funds. Similarly, the proportion of senior capital in a company's capitalization is the measure of financial risk which is often analyzed in the context of the equity ratio (i.e., the complement of the debt ratio).

COST OF EQUITY--GENERAL APPROACH

Through a fundamental financial analysis, the relative risk of a firm must be established prior to the determination of its cost of equity. Any rate of return recommendation which lacks such a basis will inevitably fail to provide a utility with a fair rate of return except by coincidence. With a fundamental risk analysis as a foundation, standard financial models can be employed by using informed judgment. The methods which have been employed to measure the cost of equity include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") approach, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.

The traditional DCF model, while useful in providing some insight into the cost of equity, is not an approach that should be used exclusively. The divergence of stock prices from company-specific fundamentals can provide a misleading cost of equity calculation. As reported in The Wall Street Journal on June 6, 1991, a statistical study published by Goldman Sachs indicated that only 35% of stock price growth in the 1980's could be attributed to earnings and interest rates. Further, 38% of the rise in stock prices during the 1980's was attributed to unknown factors. The Goldman Sachs study highlights the serious limitations of a model, such as DCF, which is founded upon identification of specific variables to explain stock price growth. That is to say, when stock price growth exceeds growth in a company's earnings per share, models such as DCF will misspecify investor expected returns which are comprised of capital gains, as well as dividend receipts. As such, a combination of methods should be used to measure the cost of equity.

The Risk Premium analysis is founded upon the prospective cost of long-term debt, i.e., the yield that the public utility must offer to raise long-term debt capital directly from investors. To that yield must be added a risk premium in recognition of the greater risk of common equity over debt. This additional risk is, of course, attributable to the fact that the payment of interest and principal to creditors has priority over the payment of dividends and return of capital to equity investors. Hence, equity investors require a higher rate of return than the yield on long-term corporate bonds.

The CAPM is a model not unlike the traditional Risk Premium. The CAPM employs the yield on a risk-free interest-bearing obligation plus a premium as compensation for risk. Aside from the reliance on the risk-free rate of return, the CAPM gives specific quantification to systematic (or market) risk as measured by beta.

The Comparable Earnings approach measures the returns expected/experienced by other non-regulated firms and has been used extensively in rate of return analysis for over a half century. However, its popularity diminished in the 1970s and 1980s with the popularization of market-based models. Recently, there has been renewed interest in this approach. Indeed, the financial community has expressed the view that the regulatory process must consider the returns which are being achieved in the non-regulated sector so that public utilities can compete effectively in the capital markets. Indeed, with additional competition being introduced throughout the traditionally regulated public utility industry, returns expected to be realized by non-regulated firms have become increasing relevant in the ratesetting process. The Comparable Earnings approach considers directly those requirements and it fits the established standards for a fair rate of return set forth in the Bluefield decision. The Bluefield decisions requires that a fair return for a utility must be equal to that earned by firms of comparable risk.

DISCOUNTED CASH FLOW ANALYSIS

Discounted Cash Flow ("DCF") theory seeks to explain the value of an economic or financial asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. Thus, if \$100 is to be received in a single payment 10 years subsequent to the acquisition of an asset, and the appropriate risk-related interest rate is 8%, the present value of the asset would be \$46.32 (Value = \$100 ÷ $(1.08)^{10}$) arising from the discounted future cash flow. Conversely, knowing the present \$46.32 price of an asset (where price = value), the \$100 future expected cash flow to be received 10 years hence shows an 8% annual rate of return implicit in the price and future cash flows expected to be received.

In its simplest form, the DCF theory considers the number of years from which the cash flow will be derived and the annual compound interest rate which reflects the risk or uncertainty associated with the cash flows. It is appropriate to reiterate that the dollar values to be discounted are future cash flows.

DCF theory is flexible and can be used to estimate value (or price) or the annual required rate of return under a wide variety of conditions. The theory underlying the DCF methodology can be easily illustrated by utilizing the investment horizon associated with a preferred stock not having an annual sinking fund provision. In this case, the investment horizon is infinite, which reflects the perpetuity of a preferred stock. If *P* represents price, *Kp* is the required rate of return on a preferred stock, and *D* is the annual dividend (*P* and *D* with time subscripts), the value of a preferred share is equal to the present value of the dividends to be received in the future discounted at the appropriate risk-adjusted interest rate, *Kp*. In this circumstance:

$$P_0 = \frac{D_1}{(1+Kp)} + \frac{D_2}{(1+Kp)^2} + \frac{D_3}{(1+Kp)^3} + \ldots + \frac{D_n}{(1+Kp)^n}$$

If $D_1 = D_2 = D_3 = \ldots D_n$ as is the case for preferred stock, and n approaches infinity, as is the case for non-callable preferred stock without a sinking fund, then this equation reduces to:

$$P_0 = \frac{D_1}{Kp}$$

This equation can be used to solve for the annual rate of return on a preferred stock when the current price and subsequent annual dividends are known. For example, with D_1 = \$1.00, and P_0 = \$10, then Kp = \$1.00 ÷ \$10, or 10%.

The dividend discount equation, first shown, is the generic DCF valuation model for all equities, both preferred and common. While preferred stock generally pays a constant dividend, permitting the simplification subsequently noted, common stock dividends are not constant. Therefore, absent some other simplifying condition, it is necessary to rely upon the generic form of the DCF. If, however, it is assumed that $D_1, D_2, D_3, \ldots D_n$ are systematically related to one another by a constant growth rate (g), so that $D_0\,(1 + g) = D_1$, $D_1\,(1 + g) = D_2$, $D_2\,(1 + g) = D_3$ and so on approaching infinity, and if Ks (the required rate of return on a common stock) is greater than g, then the DCF equation can be reduced to:

$$P_0 = \frac{D_1}{Ks - g} \quad or \quad P_0 = \frac{D_0(1+g)}{Ks - g}$$

which is the periodic form of the "Gordon" model.[1] Proof of the DCF equation is found in all modern basic finance textbooks. This DCF equation can be easily solved as:

$$Ks = \frac{D_0(1+g)}{P_0} + g$$

which is the periodic form of the Gordon Model commonly applied in estimating equity rates of return in rate cases. When used for this purpose, Ks is the annual rate of return on common equity demanded by investors to induce them to hold a firm's common stock. Therefore, the

1 Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

variables D_0, P_0 and g must be estimated in the context of the market for equities, so that the rate of return, which a public utility is permitted the opportunity to earn, has meaning and reflects the investor-required cost rate.

Application of the Gordon model with market derived variables is straightforward. For example, using the most recent prior annualized dividend (D_0) of \$0.80, the current price (P_0) of \$10.00, and the investor expected dividend growth rate (g) of 5%, the solution of the DCF formula provides a 13.4% rate of return. The dividend yield component in this instance is 8.4%, and the capital gain component is 5%, which together represent the total 13.4% annual rate of return required by investors. The capital gain component of the total return may be calculated with two adjacent future year prices. For example, in the eleventh year of the holding period, the price per share would be \$17.10 as compared with the price per share of \$16.29 in the tenth year which demonstrates the 5% annual capital gain yield.

Some DCF devotees believe that it is more appropriate to estimate the required return on equity with a model which permits the use of multiple growth rates. This may be a plausible approach to DCF, where investors expect different dividend growth rates in the near term and long run. If two growth rates, one near term and one long-run, are to be used in the context of a price (P_0) of \$10.00, a dividend (D_0) of \$0.80, a near-term growth rate of 5.5%, and a long-run expected growth rate of 5.0% beginning at year 6, the required rate of return is 13.57% solved with a computer by iteration.

Use of DCF in Ratesetting

The DCF method can provide a misleading measure of the cost of equity in the ratesetting process when stock prices diverge from book values by a meaningful margin. When the difference between share values and book values is significant, the results from the DCF can result in a misspecified cost of equity when those results are applied to book value. This is because investor expected returns, as described by the DCF model, are related to the market value of common stock. This discrepancy is shown by the following example. If it is assumed, hypothetically, that investors require a 12.5% return on their common stock investment value (i.e., the market price per share) when share values represent 150% of book value, investors would require a total annual return of \$1.50 per share on a \$12.00 market value to realize their expectations. If, however, this 12.5% market-determined cost rate is applied to an original cost rate base which is equivalent to the book value of common stock of $8.00 per share, the utility's actual earnings per share would be only $1.00. This would result in a $.50 per share earnings shortfall which would deny the utility the ability to satisfy investor expectations.

As a consequence, a utility could not withstand these DCF results applied in a rate case and also sustain its financial integrity. This is because $1.00 of earnings per share and a 75% dividend payout ratio would provide earnings retention growth of just 3.125% (i.e., $1.00 x .75 = $0.75, and $1.00 - $0.75 = $0.25 ÷ $8.00 = 3.125%). In this example, the earnings retention growth rate plus the 6.25% dividend yield ($0.75 ÷ $12.00) would equal 9.375% (6.25% + 3.125%) as indicated by the DCF model. This DCF result is the same as the utility's rate of dividend payments on its book value (i.e., $0.75 ÷ $8.00 = 9.375%). This situation provides the utility with no earnings cushion for its dividend payment because the DCF result equals the dividend rate on book value (i.e., both rates are 9.375% in the example). Moreover, if the price employed in my example were higher than 150% of book value, a "negative" earnings cushion would develop and cause the need for a dividend reduction because the DCF result would be less than the dividend rate on book value. For these reasons, the usefulness of the DCF method significantly diminishes as market prices and book values diverge.

Further, there is no reason to expect that investors would necessarily value utility stocks equal to their book value. In fact, it is rare that utility stocks trade at book value. Moreover, high market-to-book ratios may be reflective of general market sentiment. Were regulators to use the results of a DCF model, that fails to produce the required return when applied to an original cost rate base, they would penalize a company with high market-to-book ratios. This clearly would penalize a regulated firm and its investors that purchased the stock at its current price. When investor expectations are not fulfilled, the market price per share will decline and a new, different equity cost rate would be indicated from the lower price per share. This condition suggests that the current price would be subject to disequilibrium and would not allow a reasonable calculation of the cost of equity. This situation would also create a serious disincentive for management initiative and efficiency. Within that framework, a perverse set of goals and rewards would result, i.e., a high authorized rate of return in a rate case would be the reward for poor financial performance, while low rates of return would be the reward for good financial performance. As such, the DCF results should not be used alone to determine the cost of equity, but should be used along with other complementary methods.

Dividend Yield

The historical annual dividend yield for the Gas Group is shown on Schedule 2. The 2001-2005 five-year average dividend yield was 5.1% for the Gas Group. The monthly dividend yields for the past twelve months are shown graphically on Schedule 4. These dividend yields reflect an adjustment to the month-end closing prices to remove the pro rata accumulation of the quarterly dividend amount since the last ex-dividend date.

The ex-dividend date usually occurs two business days before the record date of the dividend (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment--usually about two to three weeks prior to the actual payment). During a quarter (here defined as 91 days), the price of a stock moves up ratably by the dividend amount as the ex-dividend date approaches. The stock's price then falls by the amount of the dividend on the ex-dividend date. Therefore, it is necessary to calculate the fraction of the quarterly dividend since the time of the last ex-dividend date and to remove that amount from the price. This adjustment reflects normal recurring pricing of stocks in the market, and establishes a price which will reflect the true yield on a stock.

A six-month average dividend yield has been used to recognize the prospective orientation of the ratesetting process as explained in the direct testimony. For the purpose of a DCF calculation, the average dividend yields must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future rather than the recent dividend payment annualized. An adjustment to the dividend yield component, when computed with annualized dividends, is required based upon investor expectation of quarterly dividend increases.

The procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, developed below. The DCF equation, showing the quarterly dividend payments as D_0, may be stated in this fashion:

$$K = \frac{D_0(1+g)^0 + D_0(1+g)^0 + D_0(1+g)^1 + D_0(1+g)^1}{P_0} + g$$

The adjustment factor, based upon one-half the expected growth rate developed in my direct testimony, will be 2.875% (5.75% x .5) for the Gas Group, which assumes that two dividend payments will be at the expected higher rate during the initial investment period. Using the six-month average dividend yield as a base, the prospective (forward) dividend yield would be 3.92% (3.81% x 1.02875) for the Gas Group.

Another DCF model that reflects the discrete growth in the quarterly dividend (D_0) is as follows:

$$K = \frac{D_0(1+g)^{.25} + D_0(1+g)^{.50} + D_0(1+g)^{.75} + D_0(1+g)^{1.00}}{P_0} + g$$

This procedure confirms the reasonableness of the forward dividend yield previously calculated. The quarterly discrete adjustment provides a dividend yield of 3.95% (3.81% x 1.03569) for the Gas Group. The use of an adjustment is required for the periodic form of the DCF in order to properly recognize that dividends grow on a discrete basis.

In either of the preceding DCF dividend yield adjustments, there is no recognition for the compound returns attributed to the quarterly dividend payments. Investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0), results in a third DCF formulation:

$$k = \left[\left(1 + \frac{D_0}{P_0}\right)^4 - 1\right] + g$$

This DCF equation provides no further recognition of growth in the quarterly dividend. Combining discrete quarterly dividend growth with quarterly compounding would provide the following DCF formulation, stating the quarterly dividend payments (D_0):

$$k = \left[\left(1 + \frac{D_0(1+g)^{.25}}{P_0}\right)^4 - 1\right] + g$$

A compounding of the quarterly dividend yield provides another procedure to recognize the necessity for an adjusted dividend yield. The unadjusted average quarterly dividend yield was 0.9525% (3.81% ÷ 4) for the Gas Group. The compound dividend yield would be 3.92% (1.009659^4-1) for the Gas Group, recognizing quarterly dividend payments in a forward-looking manner. These dividend yields conform with investors' expectations in the context of reinvestment of their cash dividend.

For the Gas Group, a 3.93% forward-looking dividend yield is the average (3.92% + 3.95% + 3.92% = 11.79% ÷ 3) of the adjusted dividend yield using the form $D_0/P_0\ (1+.5g)$, the dividend yield recognizing discrete quarterly growth, and the quarterly compound dividend yield with discrete quarterly growth.

Growth Rate

If viewed in its infinite form, the DCF model is represented by the discounted value of an endless stream of growing dividends. It would, however, require 100 years of future dividend payments so that the discounted value of those payments would equate to the present price so that the discount rate and the rate of return shown by the simplified Gordon form of the DCF model would be about the same. A century of dividend receipts represents an unrealistic investment horizon from almost any perspective. Because stocks are not held by investors forever, the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, investor expected returns in the equity market are provided by capital appreciation of the investment as well as receipt of dividends. As such, the sale price of a stock can be viewed as a liquidating dividend which can be discounted along with the annual dividend receipts during the investment holding period to arrive at the investor expected return.

In its constant growth form, the DCF assumes that with a constant return on book common equity and constant dividend payout ratio, a firm's earnings per share, dividends per share and book value per share will grow at the same constant rate, absent any external financing by a firm. Because these constant growth assumptions do not actually prevail in the capital markets, the capital appreciation potential of an equity investment is best measured by the expected growth in earnings per share. Since the traditional form of the DCF assumes no change in the price-earnings multiple, the value of a firm's equity will grow at the same rate as earnings per share. Hence, the capital gains yield is best measured by earnings per share growth using company-specific variables.

Investors consider both historical and projected data in the context of the expected growth rate for a firm. An investor can compute historical growth rates using compound growth rates or growth rate trend lines. Otherwise, an investor can rely upon published growth rates as provided in widely-circulated, influential publications. However, a traditional constant growth DCF analysis that is limited to such inputs suffers from the assumption of no change in the price-earnings multiple, i.e., that the value of a firm's equity will grow at the same rate as earnings. Some of the factors which actually contribute to investors' expectations of earnings growth and which should be considered in assessing those expectations, are: (i) the earnings rate on existing equity, (ii) the portion of earnings not paid out in dividends, (iii) sales of additional common equity, (iv) reacquisition of common stock previously issued, (v) changes in financial leverage, (vi) acquisitions of new business opportunities, (vii) profitable liquidation of assets, and (viii) repositioning of existing assets. The realities of the equity market regarding total return expectations, however, also reflect factors other than these inputs. Therefore, the DCF model contains overly restrictive limitations when the growth component is stated in terms of earnings per share (the basis for the capital gains yield) or dividends per share (the basis for the infinite dividend discount model). In these situations, there is inadequate recognition of the capital gains yields arising from stock price growth which could exceed earnings or dividends growth.

To assess the growth component of the DCF, analysts' projections of future growth influence investor expectations as explained above. One influential publication is The Value Line Investment Survey which contains estimated future projections of growth. The Value Line Investment Survey provides growth estimates which are stated within a common economic environment for the purpose of measuring relative growth potential. The basis for these projections is the Value Line 3 to 5 year hypothetical economy. The Value Line hypothetical economic environment is represented by components and subcomponents of the National Income Accounts which reflect in the aggregate assumptions concerning the unemployment rate, manpower productivity, price inflation, corporate income tax rate, high-grade corporate bond interest rates, and Fed policies. Individual estimates begin with the correlation of sales, earnings and dividends of a company to appropriate components or subcomponents of the future National Income Accounts. These calculations provide a consistent basis for the published forecasts. Value Line's evaluation of a specific company's future prospects are considered in the context of specific operating characteristics that influence the published projections. Of particular importance for regulated firms, Value Line considers the regulatory quality, rates of return recently authorized, the historic ability of the firm to actually experience the authorized rates of return, the firm's budgeted capital spending, the firm's financing forecast, and the dividend payout ratio. The wide circulation of this source and frequent reference to Value Line in financial circles indicate that this publication has an influence on investor judgment with regard to expectations for the future.

There are other sources of earnings growth forecasts. One of these sources is the Institutional Brokers Estimate System ("IBES"). The IBES service provides data on consensus earnings per share forecasts and five-year earnings growth rate estimates. The publisher of IBES has been purchased by Thomson/First Call. The IBES forecasts have been integrated into the First Call consensus growth forecasts. The earnings estimates are obtained from financial analysts at brokerage research departments and from institutions whose securities analysts are projecting earnings for companies in the First Call universe of companies. Other services that tabulate earnings forecasts and publish them are Zacks Investment Research and Market Guide (which is provided over the Internet by Reuters). As with the IBES/First Call forecasts, Zacks and Reuters/Market Guide provide consensus forecasts collected from analysts for most publically traded companies.

In each of these publications, forecasts of earnings per share for the current and subsequent year receive prominent coverage. That is to say, IBES/First Call, Zacks, Reuters/Market Guide, and Value Line show estimates of current-year earnings and projections for the next year. While the DCF model typically focusses upon long-run estimates of growth, stock prices are clearly influenced by current and near-term earnings prospects. Therefore, the near-term earnings per share growth rates should also be factored into a growth rate determination.

Although forecasts of future performance are investor influencing[2], equity investors may

[2] As shown in a National Bureau of Economic Research monograph by John G. Cragg and Burton

also rely upon the observations of past performance. Investors' expectations of future growth rates may be determined, in part, by an analysis of historical growth rates. It is apparent that any serious investor would advise himself/herself of historical performance prior to taking an investment position in a firm. Earnings per share and dividends per share represent the principal financial variables which influence investor growth expectations.

Other financial variables are sometimes considered in rate case proceedings. For example, a company's internal growth rate, derived from the return rate on book common equity and the related retention ratio, is sometimes considered. This growth rate measure is represented by the Value Line forecast "*BxR*" shown on Schedule 6 Internal growth rates are often used as a proxy for book value growth. Unfortunately, this measure of growth is often not reflective of investor-expected growth. This is especially important when there is an indication of a prospective change in dividend payout ratio, earned return on book common equity, change in market-to-book ratios or other fundamental changes in the character of the business. Nevertheless, I have also shown the historical and projected growth rates in book value per share and internal growth rates.

G. Malkiel, Expectations and the Structure of Share Prices, University of Chicago Press 1982.

FLOTATION COST ADJUSTMENT

The rate of return on common equity must be high enough to avoid dilution when additional common equity is issued. In this regard, the rate of return on book common equity for public utilities requires recognition of specific factors other than just the market-determined cost of equity. A market price of common stock above book value is necessary to attract future capital on reasonable terms in competition with other seekers of equity capital. Non-regulated companies traditionally have experienced common stock prices consistently above book value. For a public utility to be competitive in the capital markets, similar recognition should be provided, given the understated value of net plant investment which is represented by historical costs much lower than current cost. Moreover, the market value of a public utility stock must be above book value to provide recognition of market pressure, issuance and selling expenses which reduce the net proceeds realized from the sale of new shares of common stock. A market price of stock above book value will maintain the financial integrity of shares previously issued and is necessary to avoid dilution when new shares are offered.

The rate of return on common equity should provide for the underwriting discount and company issuance expenses associated with the sale of new common stock. It is the net proceeds, after payment of these costs that are available to the company, because the issuance costs are paid from the initial offering price to the public. Market pressure occurs when the news of an impending issue of new common shares impacts the pre-offering price of stock. The stock price often declines because of the prospect of an increase in the supply of shares. The difficulty encountered in measuring market pressure relates to the time frame considered, general market conditions, and management action during the offering period. An indication of negative market pressure could be the product of the techniques employed to measure pressure and not the prospect of an additional supply of shares related to the new issue.

Even in the situation where a company will not issue common stock during the near term, the flotation cost adjustment factor should be applied to the common equity cost rate. A public utility must be in a competitive capital attraction posture at all times. To deny recognition of a market value of equity above book value would be discriminatory when other comparable companies receive an allowance in this regard. Moreover, to reduce the return rate on common equity by failing to recognize this factor would likewise result in a company being less competitive in the bond market, because a lower resulting overall rate of return would provide less competitive fixed-charge coverage. It cannot be said that a public utility's stock price already considers an allowance for flotation costs. This is because investors in either fixed-income bonds or common stocks seek their required rate of return by reference to alternative investment opportunities, and are not concerned with the issuance costs incurred by a firm borrowing long-term debt or issuing common equity.

Historical data concerning issuance and selling expenses (excluding market pressure) is shown on Schedule 7. To adjust for the cost of raising new common equity capital, the rate of return on common equity should recognize an appropriate multiple in order to allow for a market price of stock above book value. This would provide recognition for flotation costs, which are shown to be 3.9% for public offerings of common stocks by gas companies from 2001 to 2005. Because these costs are not recovered elsewhere, they must be recognized in the rate of return. Since I apply the flotation cost to the entire cost of equity, I have only used a modification factor of 1.02 which is applied to the unadjusted DCF-measure of the cost of equity to cover issuance expense. If the modification factor were applied to only a portion of the cost of equity, such as just the dividend yield, then a higher factor would be necessary.

INTEREST RATES

Interest rates can be viewed in their traditional nominal terms (i.e., the stated rate of interest) and in real terms (i.e., the stated rate of interest less the expected rate of inflation). Absent consideration of inflation, the real rate of interest is determined generally by supply factors which are influenced by investors willingness to forego current consumption (i.e., to save) and demand factors that are influenced by the opportunities to derive income from productive investments. Added to the real rate of interest is compensation required by investors for the inflationary impact of the declining purchasing power of their income received in the future. While interest rates are clearly influenced by the changing annual rate of inflation, it is important to note that the expected rate of inflation, that is reflected in current interest rates, may be quite different than the prevailing rate of inflation.

Rates of interest also vary by the type of interest bearing instrument. Investors require compensation for the risk associated with the term of the investment and the risk of default. The risk associated with the term of the investment is usually shown by the yield curve, i.e., the difference in rates across maturities. The typical structure is represented by a positive yield curve which provides progressively higher interest rates as the maturities are lengthened. Flat (i.e., relatively level rates across maturities) or inverted (i.e., higher short-term rates than long-term rates) yield curves occur less frequently.

The risk of default is typically associated with the creditworthiness of the borrower. Differences in interest rates can be traced to the credit quality ratings assigned by the bond rating agencies, such as Moody's Investors Service, Inc. and Standard & Poor's Corporation. Obligations of the United States Treasury are usually considered to be free of default risk, and hence reflect only the real rate of interest, compensation for expected inflation, and maturity risk. The Treasury has been issuing inflation-indexed notes which automatically provide compensation to investors for future inflation, thereby providing a lower current yield on these issues.

Interest Rate Environment

Federal Reserve Board ("Fed") policy actions which impact directly short-term interest rates also substantially affect investor sentiment in long-term fixed-income securities markets. In this regard, the Fed has often pursued policies designed to build investor confidence in the fixed-income securities market. Formative Fed policy has had a long history, as exemplified by the historic 1951 Treasury-Federal Reserve Accord, and more recently, deregulation within the financial system which increased the level and volatility of interest rates. The Fed has indicated that it will follow a monetary policy designed to promote non-inflationary economic growth.

As background to the recent levels of interest rates, history shows that the Open Market Committee of the Federal Reserve board ("FOMC") began a series of moves toward lower short-term interest rates in mid-1990 -- at the outset of the previous recession. Monetary policy was influenced at that time by (i) steps taken to reduce the federal budget deficit, (ii) slowing economic growth, (iii) rising unemployment, and (iv) measures intended to avoid a credit crunch. Thereafter, the Federal government initiated several bold proposals to deal with future borrowings by the Treasury. With lower expected federal budget deficits and reduced Treasury borrowings, together with limitations on the supply of new 30-year Treasury bonds, long-term interest rates declined to a twenty-year low, reaching a trough of 5.78% in October 1993.

On February 4, 1994, the FOMC began a series of increases in the Fed Funds rate (i.e., the interest rate on excess overnight bank reserves). The initial increase represented the first rise in short-term interest rates in five years. The series of seven increases doubled the Fed Funds rate to 6%. The increases in short-term interest rates also caused long-term rates to move up, continuing a trend which began in the fourth quarter of 1993. The cyclical peak in long-term interest rates was reached on November 7 and 14, 1994 when 30-year Treasury bonds attained an 8.16% yield. Thereafter, long-term Treasury bond yields generally declined.

Beginning in mid-February 1996, long-term interest rates moved upward from their previous lows. After initially reaching a level of 6.75% on March 15, 1996, long-term interest rates continued to climb and reached a peak of 7.19% on July 5 and 8, 1996. For the period leading up to the 1996 Presidential election, long-term Treasury bonds generally traded within this range. After the election, interest rates moderated, returning to a level somewhat below the previous trading range. Thereafter, in December 1996, interest rates returned to a range of 6.5% to 7.0% which existed for much of 1996.

On March 25, 1997, the FOMC decided to tighten monetary conditions through a one-quarter percentage point increase in the Fed Funds rate. This tightening increased the Fed Funds rate to 5.5%. In making this move, the FOMC stated that it was concerned by persistent strength of demand in the economy, which it feared would increase the risk of inflationary imbalances that could eventually interfere with the long economic expansion.

In the fourth quarter of 1997, the yields on Treasury bonds began to decline rapidly in response to an increase in demand for Treasury securities caused by a flight to safety triggered by the currency and stock market crisis in Asia. Liquidity provided by the Treasury market makes these bonds an attractive investment in times of crisis. This is because Treasury securities encompass a very large market which provides ease of trading and carry a premium for safety. During the fourth quarter of 1997, Treasury bond yields pierced the psychologically important 6% level for the first time since 1993.

Through the first half of 1998, the yields on long-term Treasury bonds fluctuated within a range of about 5.6% to 6.1% reflecting their attractiveness and safety. In the third quarter of 1998, there was further deterioration of investor confidence in global financial markets. This loss of confidence followed the moratorium (i.e., default) by Russia on its sovereign debt and fears associated with problems in Latin America. While not significant to the global economy in the aggregate, the August 17 default by Russia had a significant negative impact on investor confidence, following earlier discontent surrounding the crisis in Asia. These events subsequently led to a general pull back of risk-taking as displayed by banks growing reluctance to lend, worries of an expanding credit crunch, lower stock prices, and higher yields on bonds of riskier companies. These events contributed to the failure of the hedge fund, Long-Term Capital Management.

In response to these events, the FOMC cut the Fed Funds rate just prior to the mid-term Congressional elections. The FOMC's action was based upon concerns over how increasing weakness in foreign economies would affect the U.S. economy. As recently as July 1998, the FOMC had been more concerned about fighting inflation than the state of the economy. The initial rate cut was the first of three reductions by the FOMC. Thereafter, the yield on long-term Treasury bonds reached a 30-year low of 4.70% on October 5, 1998. Long-term Treasury yields below 5% had not been seen since 1967. Unlike the first rate cut that was widely anticipated, the second rate reduction by the FOMC was a surprise to the markets. A third reduction in short-term interest rates occurred in November 1998 when the FOMC reduced the Fed Funds rate to 4.75%.

All of these events prompted an increase in the prices for Treasury bonds which lead to the low yields described above. Another factor that contributed to the decline in yields on long-term Treasury bonds was a reduction in the supply of new Treasury issues coming to market due to the Federal budget surplus -- the first in nearly 30 years. The dollar amount of Treasury bonds being issued declined by 30% in two years thus resulting in higher prices and lower yields. In addition, rumors of some struggling hedge funds unwinding their positions further added to the gains in Treasury bond prices.

The financial crisis that spread from Asia to Russia and to Latin America pushed nervous investors from stocks into Treasury bonds, thus increasing demand for bonds, just when supply was shrinking. There was also a move from corporate bonds to Treasury bonds to take advantage of appreciation in the Treasury market. This resulted in a certain amount of exuberance for Treasury bond investments that formerly was reserved for the stock market. Moreover, yields in the fourth quarter of 1998 became extremely volatile as shown by Treasury yields that fell from 5.10% on September 29 to 4.70 percent on October 5, and thereafter returned to 5.10% on October 13. A decline and rebound of 40 basis points in Treasury yields in a two-week time frame is remarkable.

Beginning in mid-1999, the FOMC raised interest rates on six occasions reversing its actions in the fall of 1998. On June 30, 1999, August 24, 1999, November 16, 1999, February 2, 2000, March 21, 2000, and May 16, 2000, the FOMC raised the Fed Funds rate to 6.50%. This brought the Fed Funds rate to its highest level since 1991, and was 175 basis points higher than the level that occurred at the height of the Asian currency and stock market crisis. At the time, these actions were taken in response to more normally functioning financial markets, tight labor markets, and a reversal of the monetary ease that was required earlier in response to the global financial market turmoil.

As the year 2000 drew to a close, economic activity slowed and consumer confidence began to weaken. In two steps at the beginning and at the end of January 2001, the FOMC reduced the Fed Funds rate by one percentage point. These actions brought the Fed Funds rate to 5.50%. The FOMC described its actions as "a rapid and forceful response of monetary policy" to eroding consumer and business confidence exemplified by weaker retail sales and business spending on capital equipment and cut backs in manufacturing production. Subsequently, on March 20, 2001, April 18, 2001, May 15, 2001, June 27, 2001, and August 21, 2001, the FOMC lowered the Fed Funds in steps consisting of three 50 basis points decrements followed by two 25 basis points decrements. These actions took the Fed Funds rate to 3.50%. The FOMC observed on August 21, 2001:

> "Household demand has been sustained, but business profits and capital spending continue to weaken and growth abroad is slowing, weighing on the U.S. economy. The associated easing of pressures on labor and product markets is expected to keep inflation contained.
>
> Although long-term prospects for productivity growth and the economy remain favorable, the Committee continues to believe that against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are weighted mainly toward conditions that may generate economic weakness in the foreseeable future."

After the terrorist attack on September 11, 2001, the FOMC made two additional 50 basis points reductions in the Fed Funds rate. The first reduction occurred on September 17, 2001 and followed the four-day closure of the financial markets following the terrorist attacks. The second reduction occurred at the October 2 meeting of the FOMC where it observed:

> "The terrorist attacks have significantly heightened uncertainty in an economy that was already weak. Business and household spending as a consequence are being further damped. Nonetheless, the long-term prospects for productivity growth and the economy remain favorable and should become evident once the unusual forces restraining demand abate."

Afterward, the FOMC reduced the Fed Funds rate by 50 basis points on November 6, 2001 and by 25 basis points on December 11, 2001. In total, short-term interest rates were reduced by the FOMC eleven (11) times during the year 2001. These actions cut the Fed Funds rate by 4.75% and resulted in 1.75% for the Fed Funds rate.

In an attempt to deal with weakening fundamentals in the economy recovering from the recession that began in March 2001, the FOMC provided a psychologically important one-half percentage point reduction in the federal funds rate. The rate cut was twice as large as the market expected, and brought the fed funds rate to 1.25% on November 6, 2002. The FOMC stated that:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still-robust underlying growth in productivity, is providing important ongoing support to economic activity. However, incoming economic data have tended to confirm that greater uncertainty, in part attributable to heightened geopolitical risks, is currently inhibiting spending,

> production, and employment. Inflation and inflation expectations remain well contained.
>
> In these circumstances, the Committee believes that today's additional monetary easing should prove helpful as the economy works its way through this current soft spot. With this action, the Committee believes that, against the background of its long-run goals of price stability and sustainable economic growth and of the information currently available, the risks are balanced with respect to the prospects for both goals in the foreseeable future."

As 2003 unfolded, there was a continuing expectation of lower yields on Treasury securities. In fact, the yield on ten-year Treasury notes reached a 45-year low near the end of the second quarter of 2003. For long-term Treasury bonds, those yields culminated with a 4.24% yield on June 13, 2003. Soon thereafter, the FOMC reduced the Fed Funds rate by 25 basis points on June 25, 2003. In announcing its action, the FOMC stated:

> "The Committee continues to believe that an accommodative stance of monetary policy, coupled with still robust underlying growth in productivity, is providing important ongoing support to economic activity. Recent signs point to a firming in spending, markedly improved financial conditions, and labor and product markets that are stabilizing. The economy, nonetheless, has yet to exhibit sustainable growth. With inflationary expectations subdued, the Committee judged that a slightly more expansive monetary policy would add further support for an economy which it expects to improve over time."

Thereafter, intermediate and long-term Treasury yields moved marketedly higher. Higher yields on long-term Treasury bonds, which exceeded 5.00% can be traced to: (i) the market's disappointment that the Fed Funds rate was not reduced below 1.00%, (ii) an indication that the Fed will not use unconventional methods for implementing monetary policy, (iii) growing confidence in a strengthening economy, and (iv) a Federal budget deficit that is projected to be $455 billion in 2003 (reported, subsequently, the actually deficit was $374 billion) and $475 billion in 2004 (revised subsequently, the estimated deficit is $500 billion in 2004). All these factors significantly changed the seniment in the bond market.

For the remainder of 2003, the FOMC continued with its balanced monetary policy, thereby retaining the 1% Fed Funds rate. However, in 2004, the FOMC initiated a policy of moving toward a more neutral Fed Funds rate (i.e., removing the bias of abnormal low rates).

On June 30, 2004, August 10, 2004, September 21, 2004, November 10, 2004, December 14, 2004, February 2, 2005, March 22, 2005, May 3, 2005, June 30, 2005, August 9, 2005, September 20, 2005, November 1, 2005, December 13, 2005, January 31, 2006, March 28, 2006, May 10, 2006, and June 29, 2006, the FOMC increased the Fed Funds rate in seventeen 25 basis point increments. These policy actions are widely interpreted as part of the process of moving toward a more neutral range for the Fed Funds rate. In its January 31, 2007 press release, the FOMC stated:

> "Recent indicators have suggested somewhat firmer economic growth, and some tentative signs of stabilization have appeared in the housing market. Overall, the economy seems likely to expand at a moderate pace over coming quarters.
>
> Readings on core inflation have improved modestly in recent months, and inflation pressures seem likely to moderate over time. However, the high level of resource utilization has the potential to sustain inflation pressures.
>
> The Committee judges that some inflation risks remain. The extent and timing of any additional firming that may be needed to address these risks will depend on the evolution of the outlook for both inflation and economic growth, as implied by incoming information."

Public Utility Bond Yields

The Risk Premium analysis of the cost of equity is represented by the combination of a firm's borrowing rate for long-term debt capital plus a premium that is required to reflect the additional risk associated with the equity of a firm as explained in Appendix G. Due to the senior nature of the long-term debt of a firm, its cost is lower than the cost of equity due to the prior claim which lenders have on the earnings and assets of a corporation.

As a generalization, all interest rates track to varying degrees of the benchmark yields established by the market for Treasury securities. Public utility bond yields usually reflect the underlying Treasury yield associated with a given maturity plus a spread to reflect the specific credit quality of the issuing public utility. Market sentiment can also have an influence on the spreads as described below. The spread in the yields on public utility bonds and Treasury bonds varies with market conditions, as does the relative level of interest rates at varying maturities shown by the yield curve.

Pages 1 and 2 of Schedule 8 provide the recent history of long-term public utility bond yields for the rating categories of Aa, A and Baa (no yields are shown for Aaa rated public utility bonds because this index has been discontinued). The top four rating categories of Aaa, Aa, A, and Baa are known as "investment grades" and are generally regarded as eligible for bank investments under commercial banking regulations. These investment grades are distinguished from "junk" bonds which have ratings of Ba and below.

A relatively long history of the spread between the yields on long-term A-rated public utility bonds and 20-year Treasury bonds is shown on page 3 of Schedule 8. There, it is shown that those spreads were about the one percentage during for the years 1994 through 1997. With the aversion to risk and flight to quality described earlier, a significant widening of the spread in the yields between corporate (e.g., public utility) and Treasury bonds developed in 1998, after an initial widening of the spread that began in the fourth quarter of 1997. The significant widening of spreads in 1998 was unexpected by some technically savvy investors, as shown by the debacle at the Long-Term Capital Management hedge fund. When Russia defaulted its debt on August 17, some investors had to cover short positions when Treasury prices spiked upward. Short covering by investors that guessed wrong on the relationship between corporate and Treasury bonds also contributed to run-up in Treasury bond prices by increasing the demand for them. This helped to contribute to a widening of the spreads between corporate and Treasury bonds.

As shown on page 3 of Schedule 8, the spread in yields between A-rated public utility bonds and 20-year Treasury bonds were about one percentage point prior to 1998, 1.32% in 1998, 1.42% in 1999, 2.01% in 2000, 2.13% in 2001, 1.94% in 2002, 1.62% in 2003, 1.12% in 2004, 1.01% in 2005 and 1.08% in 2006. As shown by the monthly data presented on pages 4 and 5 of Schedule 8, the interest rate spread between the yields on 20-year Treasury bonds and A-rated public utility bonds was 1.08 percentage points for the twelve-months ended December 2006. For the six- and three-month periods ending December 2006, the yield spread was 1.07% and 1.03%, respectively.

Risk-Free Rate of Return in the CAPM

Regarding the risk-free rate of return (see Appendix H), pages 2 and 3 of Schedule 10 provide the yields on the broad spectrum of Treasury Notes and Bonds. Some practitioners of the CAPM would advocate the use of short-term treasury yields (and some would argue for the yields on 91-day Treasury Bills). Other advocates of the CAPM would advocate the use of longer-term treasury yields as the best measure of a risk-free rate of return. As Ibbotson has indicated:

> The Cost of Capital in a Regulatory Environment. When discounting cash flows projected over a long period, it is necessary to discount them by a long-term cost of capital. Additionally, regulatory processes for setting rates often specify or suggest that the desired rate of return for a regulated firm is that which would allow the firm to attract and retain debt and equity capital over the long term. Thus, the long-term cost of capital is typically the appropriate cost of capital to use in regulated ratesetting. (Stocks, Bonds, Bills and Inflation - 1992 Yearbook, pages 118-119)

As indicated above, long-term Treasury bond yields represent the correct measure of the risk-free rate of return in the traditional CAPM. Very short term yields on Treasury bills should be avoided for several reasons. First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM. Some advocates of the theory would argue that the risk-free rate of return in the CAPM should be derived from quality long-term corporate bonds.

RISK PREMIUM ANALYSIS

The cost of equity requires recognition of the risk premium required by common equities over long-term corporate bond yields. In the case of senior capital, a company contracts for the use of long-term debt capital at a stated coupon rate for a specific period of time and in the case of preferred stock capital at a stated dividend rate, usually with provision for redemption through sinking fund requirements. In the case of senior capital, the cost rate is known with a high degree of certainty because the payment for use of this capital is a contractual obligation, and the future schedule of payments is known. In essence, the investor-expected cost of senior capital is equal to the realized return over the entire term of the issue, absent default.

The cost of equity, on the other hand, is not fixed, but rather varies with investor perception of the risk associated with the common stock. Because no precise measurement exists as to the cost of equity, informed judgment must be exercised through a study of various market factors which motivate investors to purchase common stock. In the case of common equity, the realized return rate may vary significantly from the expected cost rate due to the uncertainty associated with earnings on common equity. This uncertainty highlights the added risk of a common equity investment.

As one would expect from traditional risk and return relationships, the cost of equity is affected by expected interest rates. As noted in Appendix F, yields on long-term corporate bonds traditionally consist of a real rate of return without regard to inflation, an increment to reflect investor perception of expected future inflation, the investment horizon shown by the term of the issue until maturity, and the credit risk associated with each rating category.

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a lender. The cost of equity stated in terms of the familiar risk premium approach is:

$$k=i+RP$$

where, the cost of equity *("k")* is equal to the interest rate on long-term corporate debt *("i")*, plus an equity risk premium *("RP")* which represents the additional compensation for the riskier common equity.

Equity Risk Premium

The equity risk premium is determined as the difference in the rate of return on debt capital and the rate of return on common equity. Because the common equity holder has only a residual claim on earnings and assets, there is no assurance that achieved returns on common equities will equal expected returns. This is quite different from returns on bonds, where the investor realizes the expected return during the entire holding period, absent default. It is for this reason that common equities are always more risky than senior debt securities. There are investment strategies available to bond portfolio managers that immunize bond returns against fluctuations in interest rates because bonds are redeemed through sinking funds or at maturity, whereas no such redemption is mandated for public utility common equities.

It is well recognized that the expected return on more risky investments will exceed the required yield on less risky investments. Neither the possibility of default on a bond nor the maturity risk detracts from the risk analysis, because the common equity risk rate differential (i.e., the investor-required risk premium) is always greater than the return components on a bond. It should also be noted that the investment horizon is typically long-run for both corporate debt and equity, and that the risk of default (i.e., corporate bankruptcy) is a concern to both debt and equity investors. Thus, the required yield on a bond provides a benchmark or starting point with which to track and measure the cost rate of common equity capital. There is no need to segment the bond yield according to its components, because it is the total return demanded by investors that is important for determining the risk rate differential for common equity. This is because the complete bond yield provides the basis to determine the differential, and as such, consistency requires that the computed differential must be applied to the complete bond yield when applying the risk premium approach. To apply the risk rate differential to a partial bond yield would result in a misspecification of the cost of equity because the computed differential was initially determined by reference to the entire bond return.

The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (here defined as one year) computed over long time spans. This analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved. Accordingly, historical holding period returns must not be analyzed over an unduly short period because near-term realized results may not have fulfilled investors' expectations. Moreover, specific past period results may not be representative of investment fundamentals expected for the future. This is especially apparent when the holding period returns include negative returns which are not representative of either investor requirements of the past or investor expectations for the future. The short-run phenomenon of unexpected returns (either positive or negative) demonstrates that an unduly short historical period would not adequately support a risk premium analysis. It is important to distinguish between investors' motivation to invest, which encompass positive return expectations, and the knowledge that losses can occur. No rational investor would forego payment for the use of capital, or expect loss of principal, as a basis for investing. Investors will hold cash rather than invest with the expectation of a loss.

Within these constraints, page 1 of Schedule 9 provides the historical holding period returns for the S&P Public Utility Index which has been independently computed and the historical holding period returns for the S&P Composite Index which have been reported in Stocks, Bonds, Bills and Inflation published by Ibbotson & Associates. The tabulation begins with 1928 because January 1928 is the earliest monthly dividend yield for the S&P Public Utility Index. I have considered all reliable data for this study to avoid the introduction of a particular bias to the results. The measurement of the common equity return rate differential is based upon actual capital market performance using realized results. As a consequence, the underlying data for this risk premium approach can be analyzed with a high degree of precision. Informed professional judgment is required only to interpret the results of this study, but not to quantify the component variables.

The risk rate differentials for all equities, as measured by the S&P Composite, are established by reference to long-term corporate bonds. For public utilities, the risk rate differentials are computed with the S&P Public Utilities as compared with public utility bonds.

The measurement procedure used to identify the risk rate differentials consisted of arithmetic means, geometric means, and medians for each series. Measures of the central tendency of the results from the historical periods provide the best indication of representative rates of return. In regulated ratesetting, the correct measure of the equity risk premium is the arithmetic mean because a utility must expect to earn its cost of capital in each year in order to provide investors with their long-term expectations. In other contexts, such as pension determinations, compound rates of return, as shown by the geometric means, may be appropriate. The median returns are also appropriate in ratesetting because they are a measure of the central tendency of a single period rate of return. Median values have also been considered in this analysis because they provide a return which divides the entire series of annual returns in half and are representative of a return that symbolizes, in a meaningful way, the central tendency of all annual returns contained within the analysis period. Medians are regularly included in many investor-influencing publications.

As previously noted, the arithmetic mean provides the appropriate point estimate of the risk premium. As further explained in Appendix H, the long-term cost of capital in rate cases requires the use of the arithmetic means. To supplement my analysis, I have also used the rates of return taken from the geometric mean and median for each series to provide the bounds of the range to measure the risk rate differentials. This further analysis shows that when selecting the midpoint from a range established with the geometric means and medians, the arithmetic mean is indeed a reasonable measure for the long-term cost of capital. For the years 1928 through 2006, the risk premiums for each class of equity are:

	S&P Composite	S&P Public Utilities
Arithmetic Mean	5.86%	5.41%
Geometric Mean	4.25%	3.35%
Median	10.17%	7.29%
Midpoint of Range	7.21%	5.32%
Average	6.54%	5.37%

The empirical evidence suggests that the common equity risk premium is higher for the S&P Composite Index compared to the S&P Public Utilities.

If, however, specific historical periods were also analyzed in order to match more closely historical fundamentals with current expectations, the results provided on page 2 of Schedule 9 should also be considered. One of these sub-periods included the 55-year period, 1952-2006. These years follow the historic 1951 Treasury-Federal Reserve Accord which affected monetary policy and the market for government securities.

A further investigation was undertaken to determine whether realignment has taken place subsequent to the historic 1973 Arab Oil embargo and during the deregulation of the financial markets. In each case, the public utility risk premiums were computed by using the arithmetic mean, and the geometric means and medians to establish the range shown by those values. The time periods covering the more recent periods 1974 through 2006 and 1979 through 2006 contain events subsequent to the initial oil shock and the advent of monetarism as Fed policy, respectively. For the 55-year, 33-year and 28-year periods, the public utility risk premiums were 6.40%, 5.61%, and 5.83% respectively, as shown by the average of the specific point-estimates and the midpoint of the ranges provided on page 2 of Schedule 9.

CAPITAL ASSET PRICING MODEL

Modern portfolio theory provides a theoretical explanation of expected returns on portfolios of securities. The Capital Asset Pricing Model ("CAPM") attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices. The CAPM states that the expected rate of return on a security is determined by a risk-free rate of return plus a risk premium which is proportional to the non-diversifiable (or systematic) risk of a security.

The CAPM theory has several unique assumptions that are not common to most other methods used to measure the cost of equity. As with other market-based approaches, the CAPM is an expectational concept. There has been significant academic research conducted that found that the empirical market line, based upon historical data, has a less steep slope and higher intercept than the theoretical market line of the CAPM. For equities with a beta less than 1.0, such as utility common stocks, the CAPM theoretical market line will underestimate the realistic expectation of investors in comparison with the empirical market line which shows that the CAPM may potentially misspecify investors' required return.

The CAPM considers changing market fundamentals in a portfolio context. The balance of the investment risk, or that characterized as unsystematic, must be diversified. Some argue that diversifiable (unsystematic) risk is unimportant to investors. But this contention is not completely justified because the business and financial risk of an individual company, including regulatory risk, are widely discussed within the investment community and therefore influence investors in regulated firms. In addition, I note that the CAPM assumes that through portfolio diversification, investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Because it is not known whether the average investor holds a well-diversified portfolio, the CAPM must also be used with other models of the cost of equity.

To apply the traditional CAPM theory, three inputs are required: the beta coefficient *("β")*, a risk-free rate of return *("Rf")*, and a market premium *("Rm - Rf")*. The cost of equity stated in terms of the CAPM is:

$$k = Rf + \beta\ (Rm - Rf)$$

As previously indicated, it is important to recognize that the academic research has shown that the security market line was flatter than that predicted by the CAPM theory and it had a higher intercept than the risk-free rate. These tests indicated that for portfolios with betas less than 1.0, the traditional CAPM would understate the return for such stocks. Likewise, for portfolios with betas above 1.0, these companies had lower returns than indicated by the traditional CAPM theory. Once again, CAPM assumes that through portfolio diversification investors will minimize the effect of the unsystematic (diversifiable) component of investment risk. Therefore, the CAPM must also be used with other models of the cost of equity, especially when it is not known whether the average public utility investor holds a well-diversified portfolio.

Beta

The beta coefficient is a statistical measure which attempts to identify the non-diversifiable (systematic) risk of an individual security and measures the sensitivity of rates of return on a particular security with general market movements. Under the CAPM theory, a security that has a beta of 1.0 should theoretically provide a rate of return equal to the return rate provided by the market. When employing stock price changes in the derivation of beta, a stock with a beta of 1.0 should exhibit a movement in price which would track the movements in the overall market prices of stocks. Hence, if a particular investment has a beta of 1.0, a one percent increase in the return on the market will result, on average, in a one percent increase in the return on the particular investment. An investment which has a beta less than 1.0 is considered to be less risky than the market.

The beta coefficient ("β"), the one input in the CAPM application which specifically applies to an individual firm, is derived from a statistical application which regresses the returns on an individual security (dependent variable) with the returns on the market as a whole (independent variable). The beta coefficients for utility companies typically describe a small proportion of the total investment risk because the coefficients of determination (R^2) are low.

Page 1 of Schedule 10 provides the betas published by Value Line. By way of explanation, the Value Line beta coefficient is derived from a "straight regression" based upon the percentage change in the weekly price of common stock and the percentage change weekly of the New York Stock Exchange Composite average using a five-year period. The raw historical beta is adjusted by Value Line for the measurement effect resulting in overestimates in high beta stocks and underestimates in low beta stocks. Value Line then rounds its betas to the nearest .05 increment. Value Line does not consider dividends in the computation of its betas.

Market Premium

The final element necessary to apply the CAPM is the market premium. The market premium by definition is the rate of return on the total market less the risk-free rate of return *("Rm - Rf")*. In this regard, the market premium in the CAPM has been calculated from the total return on the market of equities using forecast and historical data. The future market return is established with forecasts by Value Line using estimated dividend yields and capital appreciation potential.

With regard to the forecast data, I have relied upon the Value Line forecasts of capital appreciation and the dividend yield on the 1,700 stocks in the Value Line Survey. According to the January 19, 2007, edition of <u>The Value Line Investment Survey Summary and Index</u>, (see page 5 of Schedule 10) the total return on the universe of Value Line equities is:

	Dividend Yield	+	Median Appreciation Potential	=	Median Total Return
As of January 19, 2007	1.7%	+	8.78%[1]	=	10.48%

The tabulation shown above provides the dividend yield and capital gains yield of the companies followed by <u>Value Line</u>. Another measure of the total market return is provided by the DCF return on the S&P 500 Composite index. As shown below, that return is 12.89%.

DCF Result for the S&P 500 Composite

D/P	(	1+.5g	)	+	g	=	k
1.72%	(	1.05535	)	+	11.07%	=	12.89%

where:	Price (P)	at	31-Dec-2006	=	1418.30
	Dividend (D)	for	3rd Qtr '06	=	6.09
	Dividend (D)		annualized	=	24.36
	Growth (g)		First Call EpS	=	11.07%

Using these indicators, the total market return is 11.69% (10.48% + 12.89% = 23.37% ÷ 2) using both the <u>Value Line</u> and S&P derived returns. With the 11.69% forecast market return

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1 The estimated median appreciation potential is forecast to be 40% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 8.78% (i.e., $1.40^{.25} - 1$).

and the 5.25% risk-free rate of return, a 6.44% (11.69% - 5.25%) market premium would be indicated using forecast market data.

With regard to the historical data, I provided the rates of return from long-term historical time periods that have been widely circulated among the investment and academic community over the past several years, as shown on page 6 of Schedule 10. These data are published by Ibbotson Associates in its Stocks, Bonds, Bills and Inflation ("SBBI"). From the data provided on page 6 of Schedule 10, I calculate a market premium using the common stock arithmetic mean returns of 12.3% less government bond arithmetic mean returns of 5.8%. For the period 1926-2006, the market premium was 6.5% (12.3% - 5.8%). I should note that the arithmetic mean must be used in the CAPM because it is a single period model. It is further confirmed by Ibbotson who has indicated:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the *arithmetic* or *simple difference* of the *arithmetic* means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, *not geometric*, subtraction.
>
> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values. This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154)

For the CAPM, a market premium of 6.47% (6.5% + 6.44% = 12.94% ÷ 2) would be reasonable which is the average of the 6.5% using historical data and a market premium of 6.44% using forecasts.

COMPARABLE EARNINGS APPROACH

Value Line's analysis of the companies that it follows includes a wide range of financial and market variables, including nine items that provide ratings for each company. From these nine items, one category has been removed dealing with industry performance because, under approach employed, the particular business type is not significant. In addition, two categories have been ignored that deal with estimates of current earnings and dividends because they are not useful for comparative purposes. The remaining six categories provide relevant measures to establish comparability. The definitions for each of the six criteria (from the Value Line Investment Survey - Subscriber Guide) follow:

<u>Timeliness Rank</u>

> The rank for a stock's probable relative market performance in the year ahead. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the year-ahead market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next 12 months. Stocks ranked 3 (Average) will probably advance or decline with the market in the year ahead. Investors should try to limit purchases to stocks ranked 1 (Highest) or 2 (Above Average) for Timeliness.

<u>Safety Rank</u>

> A measure of potential risk associated with individual common stocks rather than large diversified portfolios (for which Beta is good risk measure). Safety is based on the stability of price, which includes sensitivity to the market (see Beta) as well as the stock's inherent volatility, adjusted for trend and other factors including company size, the penetration of its markets, product market volatility, the degree of financial leverage, the earnings quality, and the overall condition of the balance sheet. Safety Ranks range from 1 (Highest) to 5 (Lowest). Conservative investors should try to limit purchases to equities ranked 1 (Highest) or 2 (Above Average) for Safety.

Financial Strength

The financial strength of each of the more than 1,600 companies in the VS II data base is rated relative to all the others. The ratings range from A++ to C in nine steps. (For screening purposes, think of an A rating as "greater than" a B). Companies that have the best relative financial strength are given an A++ rating, indicating an ability to weather hard times better than the vast majority of other companies. Those who don't quite merit the top rating are given an A+ grade, and so on. A rating as low as C++ is considered satisfactory. A rating of C+ is well below average, and C is reserved for companies with very serious financial problems. The ratings are based upon a computer analysis of a number of key variables that determine (a) financial leverage, (b) business risk, and (c) company size, plus the judgment of Value Line's analysts and senior editors regarding factors that cannot be quantified across-the-board for companies. The primary variables that are indexed and studied include equity coverage of debt, equity coverage of intangibles, "quick ratio", accounting methods, variability of return, fixed charge coverage, stock price stability, and company size.

Price Stability Index

An index based upon a ranking of the weekly percent changes in the price of the stock over the last five years. The lower the standard deviation of the changes, the more stable the stock. Stocks ranking in the top 5% (lowest standard deviations) carry a Price Stability Index of 100; the next 5%, 95; and so on down to 5. One standard deviation is the range around the average weekly percent change in the price that encompasses about two thirds of all the weekly percent change figures over the last five years. When the range is wide, the standard deviation is high and the stock's Price Stability Index is low.

Beta

A measure of the sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Average. A Beta of 1.50 indicates that a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Average. Use Beta to measure the stock market risk inherent in any diversified portfolio of, say, 15 or more companies. Otherwise, use the Safety Rank, which measures total risk inherent in an equity, including that portion attributable to market fluctuations. Beta is derived from a least squares regression analysis between weekly percent changes in the price of a stock and weekly percent changes in the NYSE Average over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are periodically adjusted for their long-term tendency to regress toward 1.00.

Technical Rank

A prediction of relative price movement, primarily over the next three to six months. It is a function of price action relative to all stocks followed by Value Line. Stocks ranked 1 (Highest) or 2 (Above Average) are likely to outpace the market. Those ranked 4 (Below Average) or 5 (Lowest) are not expected to outperform most stocks over the next six months. Stocks ranked 3 (Average) will probably advance or decline with the market. Investors should use the Technical and Timeliness Ranks as complements to one another.

OHIO VALLEY GAS CORPORATION
OHIO VALLEY GAS, INC.

I.U.R.C. CAUSE NO. 43208
I.U.R.C. CAUSE NO. 43209

FINANCIAL EXHIBIT

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

PAUL R. MOUL

Ohio Valley Gas Corporation
Ohio Valley Gas, Inc.

Index of Schedules

Ohio Valley Gas Corporation and Subsidary
Capitalization and Financial Statistics
2001-2005, Inclusive

	2005	2004	2003 (Millions of Dollars)	2002	2001	Average
Amount of Capital Employed						
Permanent Capital	$ 30.4	$ 29.6	$ 29.4	$ 26.9	$ 27.0	
Short-Term Debt	$ -	$ 2.0	$ 6.8	$ 4.0	$ 6.0	
Total Capital	$ 30.4	$ 31.6	$ 36.1	$ 30.9	$ 33.0	
Capital Structure Ratios						
Based on Permanent Capital:						
Common Equity [1]	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	0.0%	6.3%	18.7%	13.0%	18.2%	11.2%
Common Equity [1]	100.0%	93.7%	81.3%	87.0%	81.8%	88.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [1]	2.5%	0.8%	9.5%	-0.7%	1.4%	2.7%
Operating Ratio [2]	96.7%	98.5%	88.2%	100.4%	98.7%	96.5%
Coverage incl. AFUDC [3]						
Pre-tax: All Interest Charges	8.42 x	3.15 x	18.61 x	-0.15 x	1.83 x	6.37 x
Post-tax: All Interest Charges	5.03 x	2.02 x	11.50 x	0.45 x	1.86 x	4.17 x
Coverage excl. AFUDC [3]						
Pre-tax: All Interest Charges	8.33 x	3.02 x	18.50 x	-0.20 x	1.46 x	6.22 x
Post-tax: All Interest Charges	4.94 x	1.88 x	11.39 x	0.39 x	1.49 x	4.02 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	2.3%	12.9%	1.0%	-9.9%	42.7%	9.8%
Effective Income Tax Rate	45.6%	52.8%	40.4%	52.0%	-3.9%	37.4%
Internal Cash Generation/Construction [4]	167.2%	105.5%	245.8%	116.1%	73.7%	141.7%
Gross Cash Flow/ Avg. Total Debt [5]	270.4%	58.9%	89.0%	32.5%	31.5%	96.5%
Gross Cash Flow Interest Coverage [6]	15.13 x	12.36 x	19.55 x	5.64 x	5.05 x	11.55 x
Common Dividend Coverage [7]	x	x	25.78 x	87.68 x	24.44 x	45.97 x

See Page 2 for Notes.

Ohio Valley Gas Corporation and Subsidiary
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.

(2) Total operating expenses, maintenance, depreciation and taxes other than income as a percentage of operating revenues.

(3) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.

(4) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally generated funds from operations after payment of all cash dividends.

(5) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less AFUDC) as a percentage of average total debt.

(6) Gross Cash Flow plus interest charges divided by interest charges.

(7) Common dividend coverage is the relationship of internally generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: BKD Certified financial statements

Gas Group
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 444.5	$ 430.6	$ 389.2	$ 362.3	$ 349.3	
Short-Term Debt	$ 56.2	$ 41.2	$ 62.0	$ 62.5	$ 66.8	
Total Capital	$ 500.7	$ 471.8	$ 451.2	$ 424.8	$ 416.1	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	17 x	18 x	14 x	16 x	14 x	16 x
Market/Book Ratio	192.3%	180.3%	164.1%	154.3%	149.2%	168.0%
Dividend Yield	3.7%	6.3%	4.7%	5.2%	5.4%	5.1%
Dividend Payout Ratio	63.4%	139.3%	65.6%	82.9%	76.8%	85.6%
Capital Structure Ratios						
Based on Permanent Capital:						
Long-Term Debt	46.3%	48.3%	50.8%	52.8%	50.8%	49.8%
Preferred Stock	0.4%	0.4%	0.4%	0.5%	0.9%	0.5%
Common Equity [2]	53.3%	51.3%	48.8%	46.7%	48.3%	49.7%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	51.7%	52.4%	55.8%	59.0%	59.8%	55.7%
Preferred Stock	0.4%	0.4%	0.4%	0.5%	0.8%	0.5%
Common Equity [2]	47.9%	47.2%	43.8%	40.6%	39.4%	43.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	11.4%	10.6%	11.8%	10.0%	10.6%	10.9%
Operating Ratio [3]	87.7%	87.5%	86.0%	85.3%	89.4%	87.2%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.74 x	3.31 x	3.23 x	2.81 x	2.71 x	3.16 x
Post-tax: All Interest Charges	2.70 x	2.45 x	2.40 x	2.13 x	2.06 x	2.35 x
Overall Coverage: All Int. & Pfd. Div.	2.70 x	2.45 x	2.39 x	2.11 x	2.04 x	2.34 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	3.74 x	3.31 x	3.20 x	2.78 x	2.67 x	3.14 x
Post-tax: All Interest Charges	2.69 x	2.44 x	2.37 x	2.09 x	2.03 x	2.32 x
Overall Coverage: All Int. & Pfd. Div.	2.69 x	2.44 x	2.37 x	2.07 x	2.00 x	2.31 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.3%	0.5%	2.1%	2.9%	3.9%	1.9%
Effective Income Tax Rate	37.7%	37.1%	37.2%	37.6%	37.8%	37.5%
Internal Cash Generation/Construction [5]	54.7%	109.1%	107.4%	75.2%	65.0%	82.3%
Gross Cash Flow/ Avg. Total Debt [6]	18.4%	22.6%	21.9%	18.0%	17.4%	19.7%
Gross Cash Flow Interest Coverage [7]	3.90 x	4.61 x	4.52 x	4.02 x	3.39 x	4.09 x
Common Dividend Coverage [8]	2.72 x	3.69 x	3.93 x	3.45 x	3.19 x	3.39 x

See Page 2 for Notes.

Gas Group
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account.
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross contribution expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(7) Gross Cash Flow plus interest charges divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Basis of Selection:
The Gas Group includes companies that (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey (either the basic or expanded issues), (iv) they have less than $1 billion of market capitalization of their equity, (v) they have not cut or omitted their dividend, and (vi) they are not currently the target of a merger or acquisition.

Ticker	Company	Corporate Credit Ratings [1] Moody's	S&P	Stock Traded	S&P Stock Ranking	Value Line Beta
CPK	Chesapeake Utilities	-	-	NYSE	B	0.60
DGAS	Delta Natural Gas Company	-	-	NDQ	B+	0.55
ENSI	EnergySouth, Inc.	-	-	NDQ	-	0.60
LG	Laclede Group, Inc.	A3	A	NYSE	B+	0.90
NWN	Northwest Natural Gas	A3	AA-	NYSE	B+	0.75
RGCO	RGC Resources, Inc.	-	-	NDQ	-	0.35
SJI	South Jersey Industries	Baa1	BBB+	NYSE	B+	0.70
	Average	A3	A-		B+	0.64

Note: [1] Ratings are those of utility subsidiaries

Source of Information: Company Annual Reports to Stockholders
Utility COMPUSTAT
Moody's Investors Service
Standard & Poor's Corporation
S&P Stock Guide

Standard & Poor's Public Utilities
Capitalization and Financial Statistics [1]
2001-2005, Inclusive

	2005	2004	2003	2002	2001	
			(Millions of Dollars)			
Amount of Capital Employed						
Permanent Capital	$ 14,644.5	$ 14,562.2	$14,658.8	$ 14,236.2	$13,783.4	
Short-Term Debt	$ 485.3	$ 278.7	$ 276.6	$ 952.3	$ 1,204.1	
Total Capital	$ 15,129.8	$ 14,840.9	$14,935.4	$ 15,188.5	$14,987.5	
Market-Based Financial Ratios						Average
Price-Earnings Multiple	18 x	15 x	13 x	15 x	17 x	16 x
Market/Book Ratio	195.5%	180.1%	149.0%	151.3%	183.6%	171.9%
Dividend Yield	3.7%	3.8%	4.2%	5.0%	4.1%	4.2%
Dividend Payout Ratio	58.9%	73.3%	59.9%	75.3%	64.1%	66.3%
Capital Structure Ratios						
Based on Permanent Captial:						
Long-Term Debt	56.6%	58.3%	59.8%	60.4%	58.9%	58.8%
Preferred Stock	1.2%	1.5%	1.6%	1.8%	2.3%	1.7%
Common Equity [2]	42.2%	40.2%	38.6%	37.8%	38.9%	39.5%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Based on Total Capital:						
Total Debt incl. Short Term	58.5%	59.7%	61.3%	63.5%	62.9%	61.2%
Preferred Stock	1.2%	1.5%	1.6%	1.6%	2.1%	1.6%
Common Equity [2]	40.3%	38.8%	37.2%	34.9%	35.0%	37.2%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rate of Return on Book Common Equity [2]	10.9%	11.1%	9.8%	7.7%	14.5%	10.8%
Operating Ratio [3]	83.0%	84.5%	84.9%	84.5%	85.9%	84.6%
Coverage incl. AFUDC [4]						
Pre-tax: All Interest Charges	3.01 x	2.88 x	2.51 x	2.36 x	2.84 x	2.72 x
Post-tax: All Interest Charges	2.41 x	2.32 x	2.07 x	1.95 x	2.22 x	2.19 x
Overall Coverage: All Int. & Pfd. Div.	2.37 x	2.28 x	2.03 x	1.90 x	2.17 x	2.15 x
Coverage excl. AFUDC [4]						
Pre-tax: All Interest Charges	2.97 x	2.85 x	2.47 x	2.31 x	2.80 x	2.68 x
Post-tax: All Interest Charges	2.37 x	2.29 x	2.03 x	1.90 x	2.18 x	2.15 x
Overall Coverage: All Int. & Pfd. Div.	2.34 x	2.25 x	1.99 x	1.86 x	2.13 x	2.11 x
Quality of Earnings & Cash Flow						
AFC/Income Avail. for Common Equity	0.9%	3.1%	1.7%	2.6%	2.0%	2.1%
Effective Income Tax Rate	31.6%	26.3%	40.9%	29.4%	28.1%	31.3%
Internal Cash Generation/Construction [5]	110.4%	127.2%	128.0%	90.6%	88.6%	109.0%
Gross Cash Flow/ Avg. Total Debt [6]	19.7%	19.7%	20.3%	18.2%	17.7%	19.1%
Gross Cash Flow Interest Coverage [7]	4.20 x	4.21 x	4.34 x	3.98 x	3.57 x	4.06 x
Common Dividend Coverage [8]	4.12 x	4.83 x	5.20 x	4.07 x	3.83 x	4.41 x

See Page 2 for Notes.

Standard & Poor's Public Utilities
Capitalization and Financial Statistics
2001-2005, Inclusive

Notes:

(1) All capitalization and financial statistics for the group are the arithmetic average of the achieved results for each individual company in the group.
(2) Excluding Accumulated Other Comprehensive Income ("OCI") from the equity account
(3) Total operating expenses, maintenance, depreciation and taxes other than income taxes as a percent of operating revenues.
(4) Coverage calculations represent the number of times available earnings, both including and excluding AFUDC (allowance for funds used during construction) as reported in its entirety, cover fixed charges.
(5) Internal cash generation/gross construction is the percentage of gross construction expenditures provided by internally-generated funds from operations after payment of all cash dividends divided by gross construction expenditures.
(6) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) as a percentage of average total debt.
(7) Gross Cash Flow (sum of net income, depreciation, amortization, net deferred income taxes and investment tax credits, less total AFUDC) plus interest charges, divided by interest charges.
(8) Common dividend coverage is the relationship of internally-generated funds from operations after payment of preferred stock dividends to common dividends paid.

Source of Information: Annual Reports to Shareholders
Utility COMPUSTAT

Standard & Poor's Public Utilities

Company Identities (1)

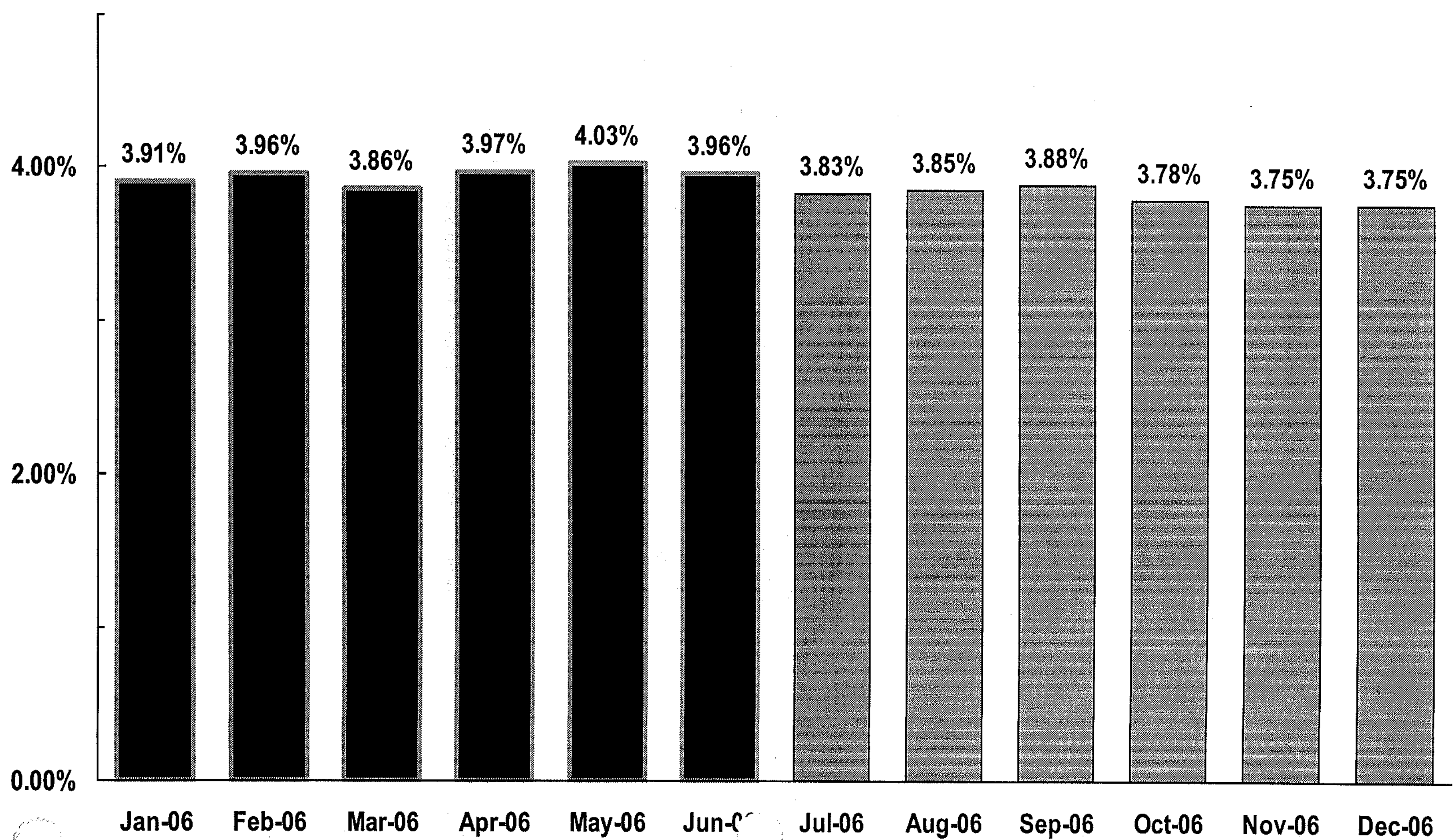
	Ticker	Credit Rating (2) Moody's	Credit Rating (2) S&P	Common Stock Traded	S&P Stock Ranking	Value Line Beta
Allegheny Energy	AYE	Baa3	BB+	NYSE	B-	1.85
Ameren Corporation	AEE	A2	BBB+	NYSE	A-	0.75
American Electric Power	AEP	Baa2	BBB	NYSE	B	1.20
CMS Energy	CMS	Ba1	BB	NYSE	C	1.45
CenterPoint Energy	CNP	Baa3	BBB	NYSE	B	0.65
Consolidated Edison	ED	A1	A	NYSE	B+	0.65
Constellation Energy Group	CEG	A3	BBB+	NYSE	B	0.95
DTE Energy Co.	DTE	Baa1	BBB	NYSE	B+	0.70
Dominion Resources	D	Baa1	BBB	NYSE	B+	0.95
Duke Energy	DUK	Baa2	BBB	NYSE	B+	1.20
Edison Int'l	EIX	Baa1	BBB+	NYSE	B	1.05
Entergy Corp.	ETR	Baa2	BBB	NYSE	B+	0.85
Exelon Corp.	EXC	A3	BBB+	NYSE	B+	0.80
FPL Group	FPL	A1	A	NYSE	A-	0.80
FirstEnergy Corp.	FE	Baa2	BBB	NYSE	B+	0.75
Keyspan Energy	KSE	A3	A	NYSE	B	0.85
NICOR Inc.	GAS	A1	AA	NYSE	B	1.15
NiSource Inc.	NI	Baa2	BBB	NYSE	B	0.80
PG&E Corp.	PCG	Baa1	BBB	NYSE	B	1.10
PPL Corp.	PPL	Baa1	A-	NYSE	B	1.00
Peoples Energy	PGL	A1	A-	NYSE	B	0.85
Pinnacle West Capital	PNW	Baa2	BBB-	NYSE	A-	0.90
Progress Energy, Inc.	PGN	Baa1	BBB	NYSE	B+	0.80
Public Serv. Enterprise Inc.	PEG	Baa1	BBB	NYSE	B+	0.90
Sempra Energy	SRE	A2	A	NYSE	B	1.00
Southern Co.	SO	A2	A	NYSE	A-	0.65
TECO Energy	TE	Baa2	BBB-	NYSE	B-	1.00
TXU CORP	TXU	Baa3	BBB-	NYSE	B	1.05
Xcel Energy Inc	XEL	A3	BBB+	NYSE	B	0.80
Average for S&P Utilities		Baa1	BBB+		B	0.95

Note: (1) Includes companies contained in S&P Utility Compustat. AES Corp. and Dynegy, Inc. are not included.
(2) Ratings are those of utility subsidiaries

Source of Information: Moody's Investors Service
Standard & Poor's Corporation
Standard & Poor's Stock Guide
Value Line Investment Survey for Windows

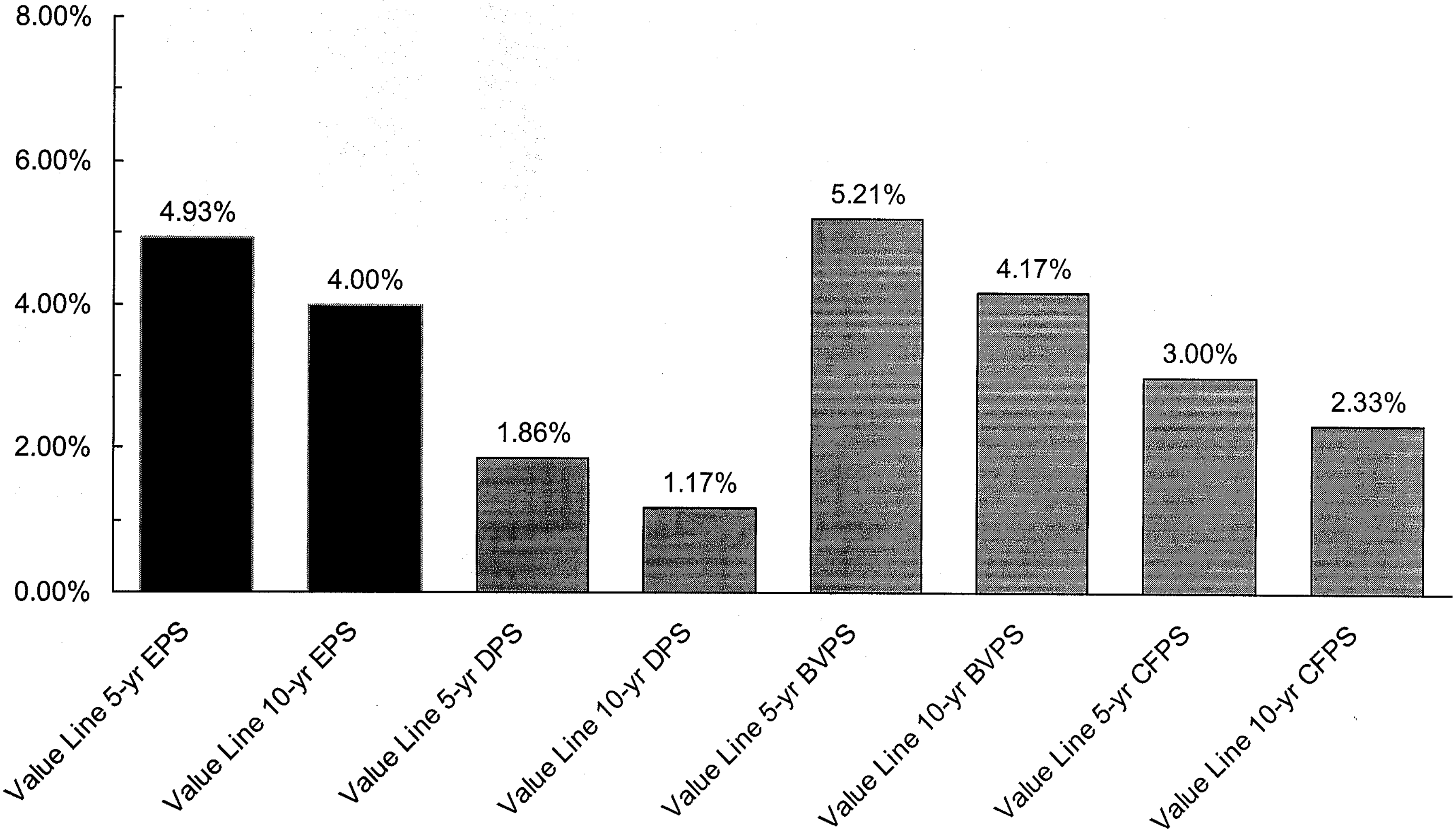
Gas Group

Monthly Dividend Yields



Gas Group

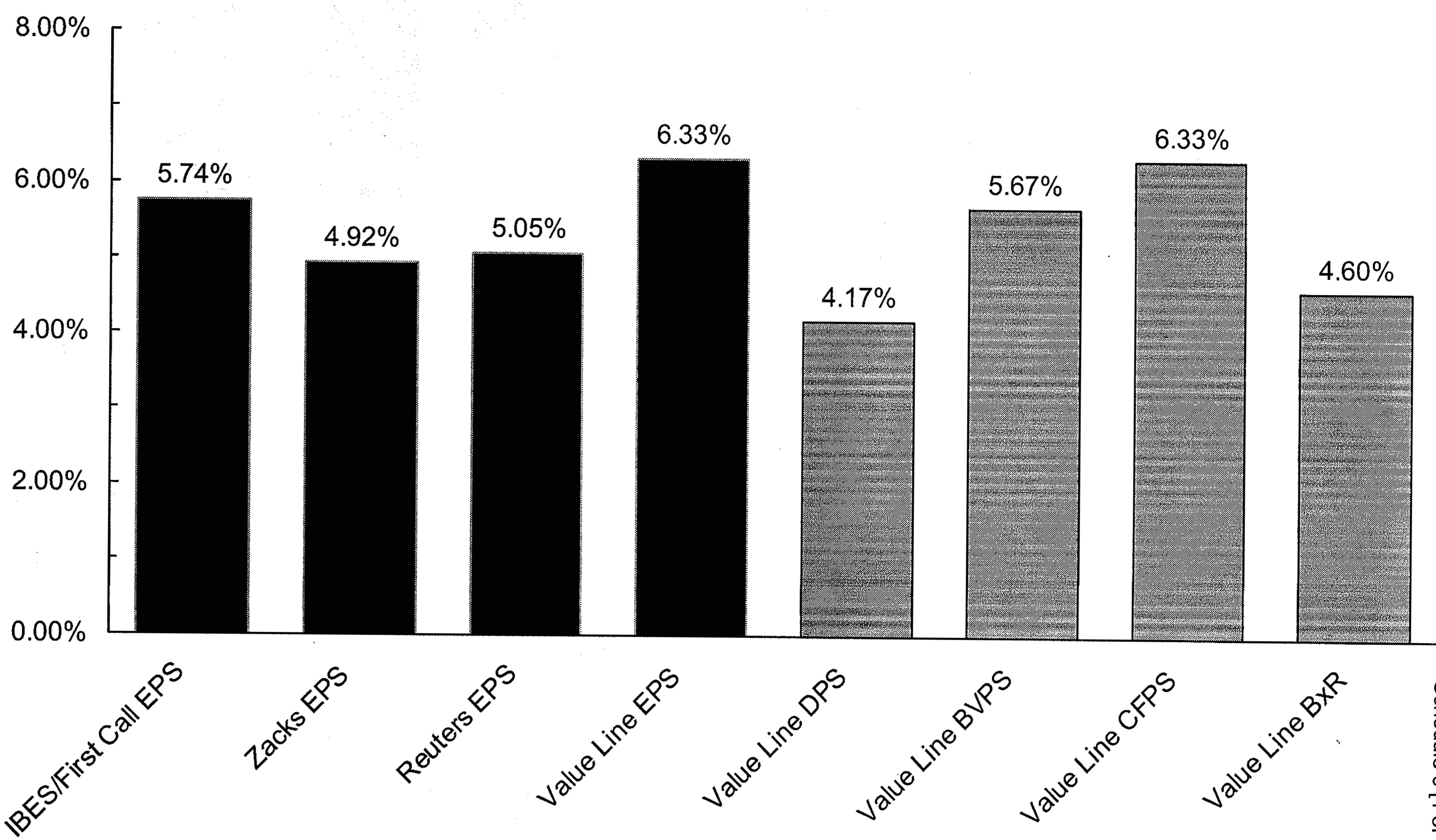
Historical Growth Rates



Earnings per Share=EPS Book Values per Share=BVPS
Dividends per Share=DPS Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

Gas Group

Five-Year Projected Growth Rates



Earnings per Share=EPS
Dividends per Share=DPS
Book Values per Share=BVPS
Cash Flow per Share=CFPS
Percent Retained to Common Equity=BxR

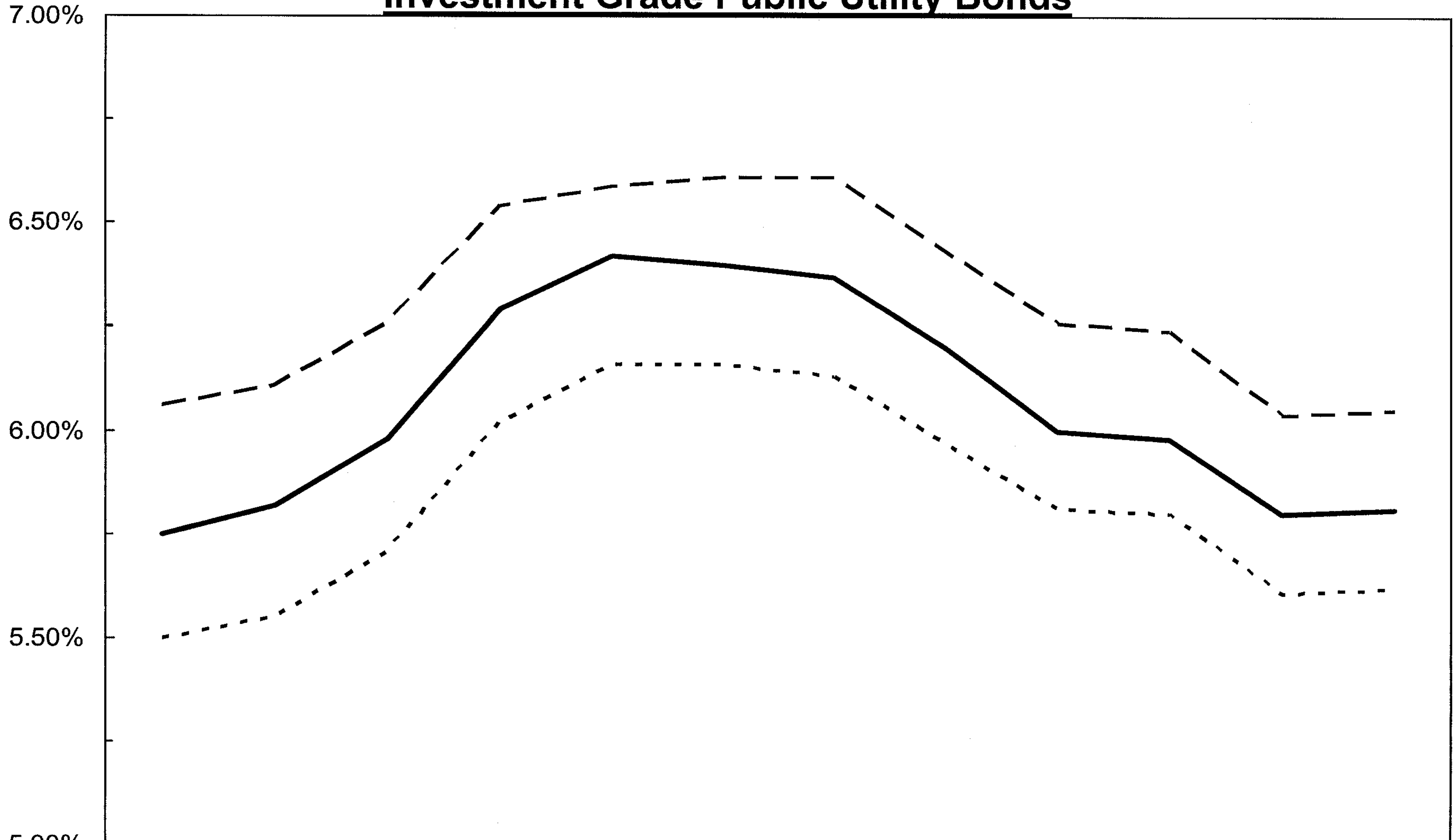
Natural Gas Industry
Analysis of Public Offerings of Common Stock
Years 2001-2005

	WGL Holdings	UTILICORP	MDU Resources	AGL RESOURCES	SOUTHERN UNION CO.	ATMOS ENERGY	VECTREN CORP.	SEMPRA ENERGY	PIEDMONT NATURAL
Date of Offering	6/26/2001	1/25/2002	11/29/2002	2/11/2003	6/5/2003	6/18/2003	8/7/2003	10/8/2003	1/20/2004
No. of shares offered (000)	1,790	11,000	2,100	5,600	9,500	4,000	6,500	15,000	4,250
Dollar amt. of offering ($000)	$ 47,847	$ 253,000	$ 50,400	$ 123,200	$ 152,000	$ 101,240	$ 148,265	$ 420,000	$ 180,625
Price to public	$ 26.730	$ 23.000	$ 24.200	$ 22.000	$ 16.000	$ 25.310	$ 22.810	$ 28.000	$ 42.500
Underwriter's discounts and commission	$ 0.895	$ 0.748	$ 0.720	$ 0.770	$ 0.560	$ 1.013	$ 0.798	$ 0.840	$ 1.490
Gross Proceeds	$ 25.835	$ 22.252	$ 23.480	$ 21.230	$ 15.440	$ 24.297	$ 22.012	$ 27.160	$ 41.010
Estimated company issuance expenses	$ 0.031	NA	$ 0.092	$ 0.045	$ 0.089	$ 0.095	$ 0.046	$ 0.033	NA
Net proceeds to company per share	$ 25.804	$ 22.252	$ 23.388	$ 21.185	$ 15.351	$ 24.202	$ 21.966	$ 27.127	$ 41.010
Underwriter's discount as a percent of offering price	3.3%	3.3%	3.0%	3.5%	3.5%	4.0%	3.5%	3.0%	3.5%
Issuance expense as a percent of offering price	0.1%	NA	0.4%	0.2%	0.6%	0.4%	0.2%	0.1%	NA
Total Issuance and selling expense as as a percent of offering price	3.4%	3.3%	3.4%	3.7%	4.1%	4.4%	3.7%	3.1%	3.5%

	UGI CORP.	NORTHWEST NATURAL	LACLEDE GROUP	SOUTHERN UNION CO.	AQUILA	ATMOS ENERGY	AGL RESOURCES	SOUTHERN UNION CO.	SEMCO Energy	Average
Date of Offering	3/18/2004	3/30/2004	5/6/2004	7/26/2004	8/18/2004	10/21/2004	11/19/2004	2/7/2005	8/9/2005	
No. of shares offered (000)	7,500	1,200	1,500	11,000	40,000	14,000	9,600	14,913	4,300	
Dollar amt. of offering ($000)	$ 240,750	$ 37,200	$ 40,200	$ 206,250	$ 102,000	$ 346,500	$ 297,696	$ 342,999	$ 27,176	
Price to public	$ 32.100	$ 31.000	$ 26.800	$ 18.750	$ 2.550	$ 24.750	$ 31.010	$ 23.000	$ 6.320	
Underwriter's discounts and commission	$ 1.404	$ 1.010	$ 0.871	$ 0.656	$ 0.099	$ 0.990	$ 0.930	$ 0.700	$ 0.253	
Gross Proceeds	$ 30.696	$ 29.990	$ 25.929	$ 18.094	$ 2.451	$ 23.760	$ 30.080	$ 22.300	$ 6.067	
Estimated company issuance expenses	$ 0.020	$ 0.146	$ 0.067	$ 0.091	NA	NA	$ 0.042	$ 0.067	$ 0.070	
Net proceeds to company per share	$ 30.676	$ 29.844	$ 25.862	$ 18.003	$ 2.451	$ 23.760	$ 30.038	$ 22.233	$ 5.997	
Underwriter's discount as a percent of offering price	4.4%	3.3%	3.3%	3.5%	3.9%	4.0%	3.0%	3.0%	4.0%	3.5%
Issuance expense as a percent of offering price	0.1%	0.5%	0.3%	0.5%	NA	NA	0.1%	0.3%	1.1%	0.4%
Total Issuance and selling expense as as a percent of offering price	4.5%	3.8%	3.6%	4.0%	3.9%	4.0%	3.1%	3.3%	5.1%	3.9%

Source of Information: Public Utility Financial Tracker

Interest Rates for
Investment Grade Public Utility Bonds



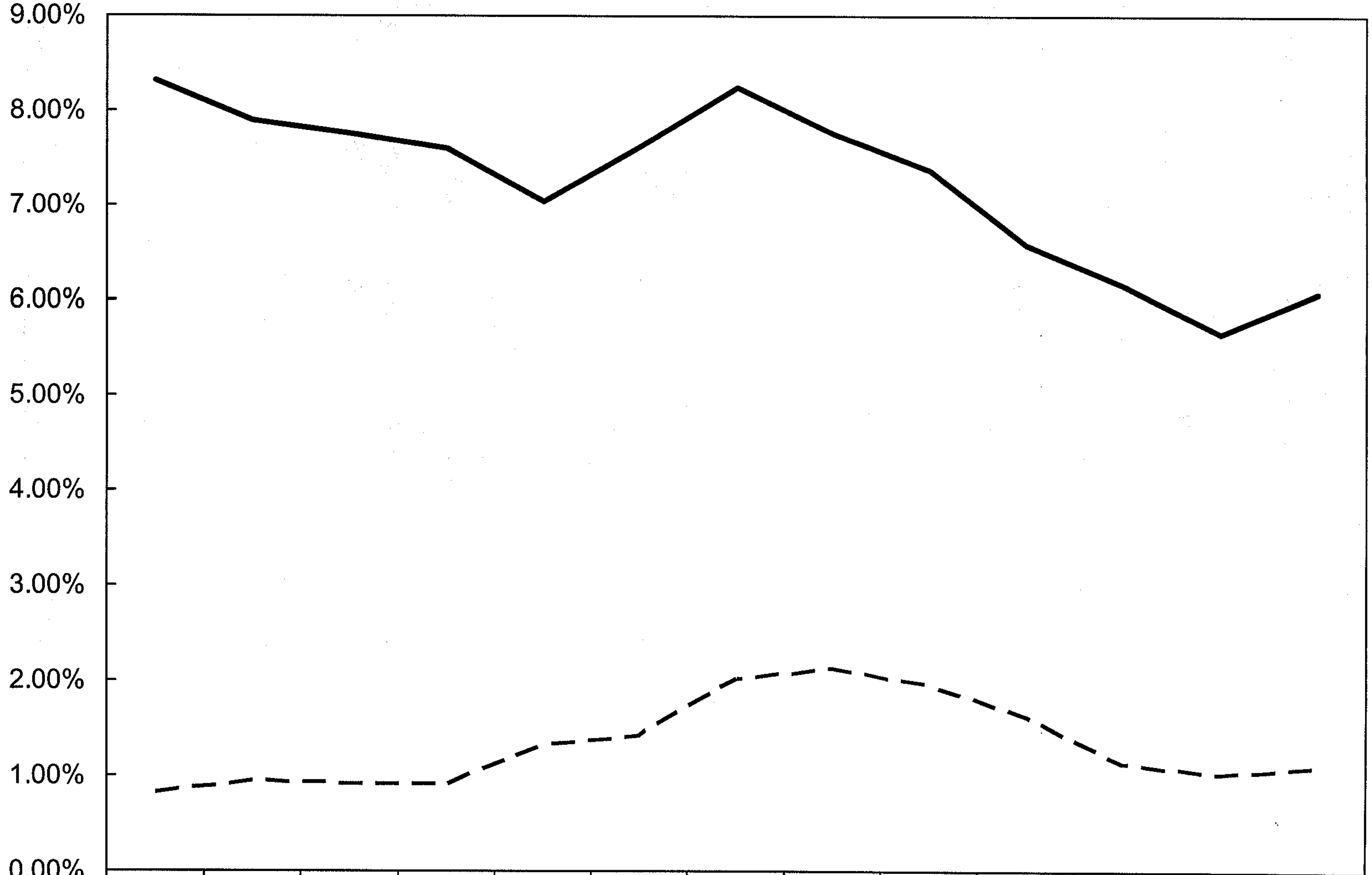
	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
- - - -Aa	5.50%	5.55%	5.71%	6.02%	6.16%	6.16%	6.13%	5.97%	5.81%	5.80%	5.61%	5.62%
——A	5.75%	5.82%	5.98%	6.29%	6.42%	6.40%	6.37%	6.20%	6.00%	5.98%	5.80%	5.81%
— — Baa	6.06%	6.11%	6.26%	6.54%	6.59%	6.61%	6.61%	6.43%	6.26%	6.24%	6.04%	6.05%

Interest Rates for Investment Grade Public Utility Bonds
Yearly for 2001-2005
and the Twelve Months Ended December 2006

Years	Aa Rated	A Rated	Baa Rated	Average
2001	7.58%	7.76%	8.03%	7.72%
2002	7.19%	7.37%	8.02%	7.53%
2003	6.40%	6.58%	6.84%	6.61%
2004	6.04%	6.16%	6.40%	6.20%
2005	5.44%	5.65%	5.93%	5.67%
Five-Year Average	6.53%	6.70%	7.04%	6.75%
Months				
Jan-06	5.50%	5.75%	6.06%	5.77%
Feb-06	5.55%	5.82%	6.11%	5.83%
Mar-06	5.71%	5.98%	6.26%	5.98%
Apr-06	6.02%	6.29%	6.54%	6.28%
May-06	6.16%	6.42%	6.59%	6.39%
Jun-06	6.16%	6.40%	6.61%	6.39%
Jul-06	6.13%	6.37%	6.61%	6.37%
Aug-06	5.97%	6.20%	6.43%	6.20%
Sep-06	5.81%	6.00%	6.26%	6.03%
Oct-06	5.80%	5.98%	6.24%	6.01%
Nov-06	5.61%	5.80%	6.04%	5.82%
Dec-06	5.62%	5.81%	6.05%	5.83%
Twelve-Month Average	5.84%	6.07%	6.32%	6.08%
Six-Month Average	5.82%	6.03%	6.27%	6.04%
Three-Month Average	5.68%	5.86%	6.11%	5.89%

Source: Mergent Bond Record

Yields on
A-rated Public Utility Bonds and
Spreads over 20-Year Treasuries



	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
A-rated Public Utility	8.31%	7.89%	7.75%	7.60%	7.04%	7.62%	8.24%	7.76%	7.37%	6.58%	6.16%	5.65%	6.07%
Spread vs. 20-year	0.82%	0.94%	0.92%	0.91%	1.32%	1.42%	2.01%	2.13%	1.94%	1.62%	1.12%	1.01%	1.08%

I.U.R.C. No. 43208
I.U.R.C. No. 43209
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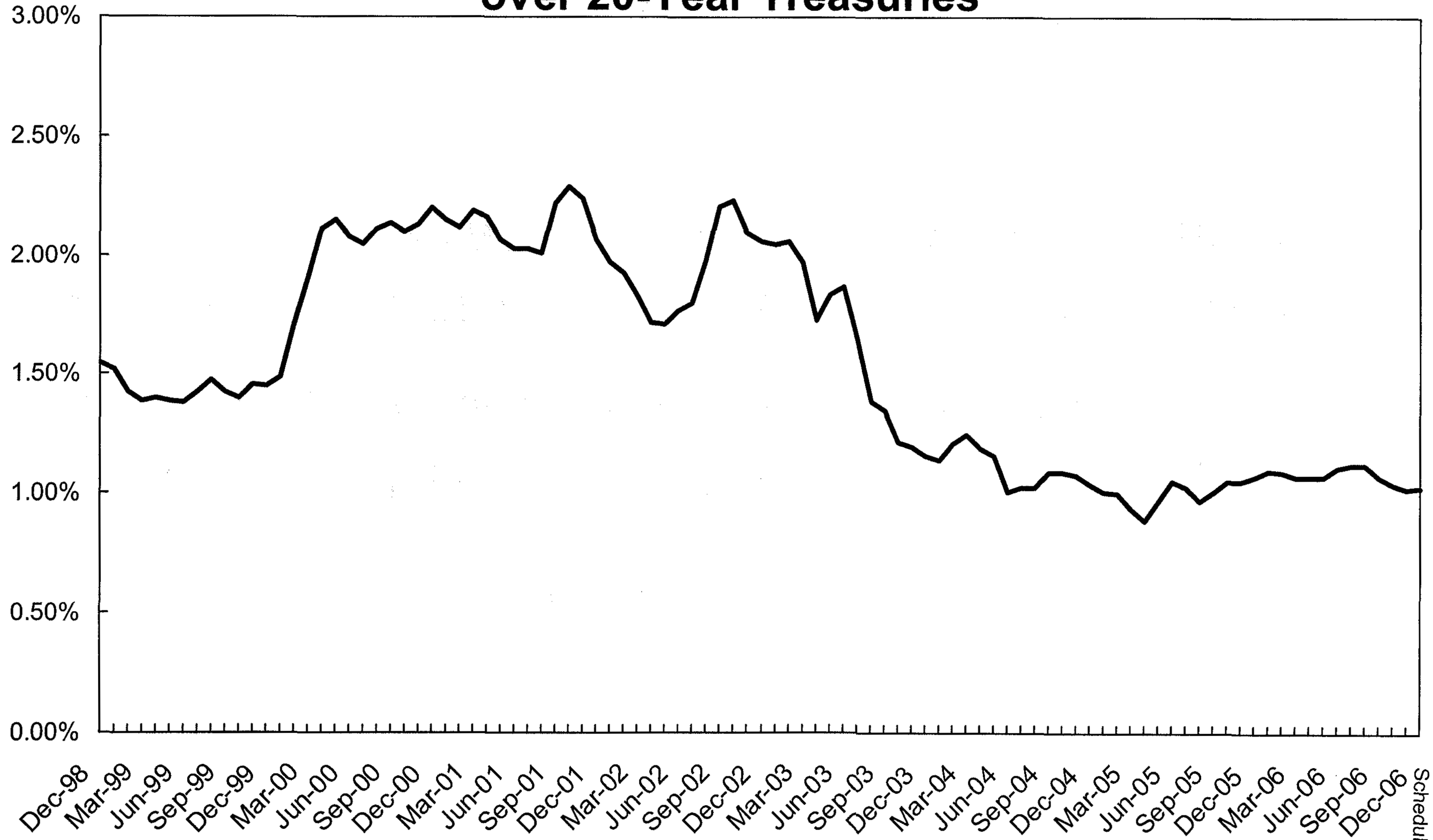
Interest Rate Spreads
A-rated Public Utility Bonds
over 20-Year Treasuries



I.U.R.C. No. 43208
I.U.R.C. No. 43209
Exhibit PRM-1
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Schedule 8 [4 of 5]

A rated Public Utility Bonds
over 20-Year Treasuries

Year	A-rated Public Utility	20-Year Treasuries Yield	Spread
Dec-98	6.91%	5.36%	1.55%
Jan-99	6.97%	5.45%	1.52%
Feb-99	7.09%	5.66%	1.43%
Mar-99	7.26%	5.87%	1.39%
Apr-99	7.22%	5.82%	1.40%
May-99	7.47%	6.08%	1.39%
Jun-99	7.74%	6.36%	1.38%
Jul-99	7.71%	6.28%	1.43%
Aug-99	7.91%	6.43%	1.48%
Sep-99	7.93%	6.50%	1.43%
Oct-99	8.06%	6.66%	1.40%
Nov-99	7.94%	6.48%	1.46%
Dec-99	8.14%	6.69%	1.45%
Jan-00	8.35%	6.86%	1.49%
Feb-00	8.25%	6.54%	1.71%
Mar-00	8.28%	6.38%	1.90%
Apr-00	8.29%	6.18%	2.11%
May-00	8.70%	6.55%	2.15%
Jun-00	8.36%	6.28%	2.08%
Jul-00	8.25%	6.20%	2.05%
Aug-00	8.13%	6.02%	2.11%
Sep-00	8.23%	6.09%	2.14%
Oct-00	8.14%	6.04%	2.10%
Nov-00	8.11%	5.98%	2.13%
Dec-00	7.84%	5.64%	2.20%
Jan-01	7.80%	5.65%	2.15%
Feb-01	7.74%	5.62%	2.12%
Mar-01	7.68%	5.49%	2.19%
Apr-01	7.94%	5.78%	2.16%
May-01	7.99%	5.92%	2.07%
Jun-01	7.85%	5.82%	2.03%
Jul-01	7.78%	5.75%	2.03%
Aug-01	7.59%	5.58%	2.01%
Sep-01	7.75%	5.53%	2.22%
Oct-01	7.63%	5.34%	2.29%
Nov-01	7.57%	5.33%	2.24%
Dec-01	7.83%	5.76%	2.07%
Jan-02	7.66%	5.69%	1.97%
Feb-02	7.54%	5.61%	1.93%
Mar-02	7.76%	5.93%	1.83%
Apr-02	7.57%	5.85%	1.72%
May-02	7.52%	5.81%	1.71%
Jun-02	7.42%	5.65%	1.77%
Jul-02	7.31%	5.51%	1.80%
Aug-02	7.17%	5.19%	1.98%
Sep-02	7.08%	4.87%	2.21%
Oct-02	7.23%	5.00%	2.23%
Nov-02	7.14%	5.04%	2.10%
Dec-02	7.07%	5.01%	2.06%
Jan-03	7.07%	5.02%	2.05%
Feb-03	6.93%	4.87%	2.06%
Mar-03	6.79%	4.82%	1.97%
Apr-03	6.64%	4.91%	1.73%
May-03	6.36%	4.52%	1.84%
Jun-03	6.21%	4.34%	1.87%
Jul-03	6.57%	4.92%	1.65%
Aug-03	6.78%	5.39%	1.39%
Sep-03	6.56%	5.21%	1.35%
Oct-03	6.43%	5.21%	1.22%
Nov-03	6.37%	5.17%	1.20%
Dec-03	6.27%	5.11%	1.16%
Jan-04	6.15%	5.01%	1.14%
Feb-04	6.15%	4.94%	1.21%
Mar-04	5.97%	4.72%	1.25%
Apr-04	6.35%	5.16%	1.19%
May-04	6.62%	5.46%	1.16%
Jun-04	6.46%	5.45%	1.01%
Jul-04	6.27%	5.24%	1.03%
Aug-04	6.14%	5.07%	1.07%
Sep-04	5.98%	4.89%	1.09%
Oct-04	5.94%	4.85%	1.09%
Nov-04	5.97%	4.89%	1.08%
Dec-04	5.92%	4.88%	1.04%
Jan-05	5.78%	4.77%	1.01%
Feb-05	5.61%	4.61%	1.00%
Mar-05	5.83%	4.89%	0.94%
Apr-05	5.64%	4.75%	0.89%
May-05	5.53%	4.56%	0.97%
Jun-05	5.40%	4.35%	1.05%
Jul-05	5.51%	4.48%	1.03%
Aug-05	5.50%	4.53%	0.97%
Sep-05	5.52%	4.51%	1.01%
Oct-05	5.79%	4.74%	1.05%
Nov-05	5.88%	4.83%	1.05%
Dec-05	5.80%	4.73%	1.07%
Jan-06	5.75%	4.65%	1.10%
Feb-06	5.82%	4.73%	1.09%
Mar-06	5.98%	4.91%	1.07%
Apr-06	6.29%	5.22%	1.07%
May-06	6.42%	5.35%	1.07%
Jun-06	6.40%	5.29%	1.11%
Jul-06	6.37%	5.25%	1.12%
Aug-06	6.20%	5.08%	1.12%
Sep-06	6.00%	4.93%	1.07%
Oct-06	5.98%	4.94%	1.04%
Nov-06	5.80%	4.78%	1.02%
Dec-06	5.81%	4.78%	1.03%

S&P Composite Index and S&P Public Utility Index
Long-Term Corporate and Public Utility Bonds
Yearly Total Returns
1928-2006

Year	S & P Composite Index	S & P Public Utility Index	Long Term Corporate Bonds	Public Utility Bonds
1928	43.61%	57.47%	2.84%	3.08%
1929	-8.42%	11.02%	3.27%	2.34%
1930	-24.90%	-21.96%	7.98%	4.74%
1931	-43.34%	-35.90%	-1.85%	-11.11%
1932	-8.19%	-0.54%	10.82%	7.25%
1933	53.99%	-21.87%	10.38%	-3.82%
1934	-1.44%	-20.41%	13.84%	22.61%
1935	47.67%	76.63%	9.61%	16.03%
1936	33.92%	20.69%	6.74%	8.30%
1937	-35.03%	-37.04%	2.75%	-4.05%
1938	31.12%	22.45%	6.13%	8.11%
1939	-0.41%	11.26%	3.97%	6.76%
1940	-9.78%	-17.15%	3.39%	4.45%
1941	-11.59%	-31.57%	2.73%	2.15%
1942	20.34%	15.39%	2.60%	3.81%
1943	25.90%	46.07%	2.83%	7.04%
1944	19.75%	18.03%	4.73%	3.29%
1945	36.44%	53.33%	4.08%	5.92%
1946	-8.07%	1.26%	1.72%	2.98%
1947	5.71%	-13.16%	-2.34%	-2.19%
1948	5.50%	4.01%	4.14%	2.65%
1949	18.79%	31.39%	3.31%	7.16%
1950	31.71%	3.25%	2.12%	2.01%
1951	24.02%	18.63%	-2.69%	-2.77%
1952	18.37%	19.25%	3.52%	2.99%
1953	-0.99%	7.85%	3.41%	2.08%
1954	52.62%	24.72%	5.39%	7.57%
1955	31.56%	11.26%	0.48%	0.12%
1956	6.56%	5.06%	-6.81%	-6.25%
1957	-10.78%	6.36%	8.71%	3.58%
1958	43.36%	40.70%	-2.22%	0.18%
1959	11.96%	7.49%	-0.97%	-2.29%
1960	0.47%	20.26%	9.07%	9.01%
1961	26.89%	29.33%	4.82%	4.65%
1962	-8.73%	-2.44%	7.95%	6.55%
1963	22.80%	12.36%	2.19%	3.44%
1964	16.48%	15.91%	4.77%	4.94%
1965	12.45%	4.67%	-0.46%	0.50%
1966	-10.06%	-4.48%	0.20%	-3.45%
1967	23.98%	-0.63%	-4.95%	-3.63%
1968	11.06%	10.32%	2.57%	1.87%
1969	-8.50%	-15.42%	-8.09%	-6.66%
1970	4.01%	16.56%	18.37%	15.90%
1971	14.31%	2.41%	11.01%	11.59%
1972	18.98%	8.15%	7.26%	7.19%
1973	-14.66%	-18.07%	1.14%	2.42%
1974	-26.47%	-21.55%	-3.06%	-5.28%
1975	37.20%	44.49%	14.64%	15.50%
1976	23.84%	31.81%	18.65%	19.04%
1977	-7.18%	8.64%	1.71%	5.22%
1978	6.56%	-3.71%	-0.07%	-0.98%
1979	18.44%	13.58%	-4.18%	-2.75%
1980	32.42%	15.08%	-2.76%	-0.23%
1981	-4.91%	11.74%	-1.24%	4.27%
1982	21.41%	26.52%	42.56%	33.52%
1983	22.51%	20.01%	6.26%	10.33%
1984	6.27%	26.04%	16.86%	14.82%
1985	32.16%	33.05%	30.09%	26.48%
1986	18.47%	28.53%	19.85%	18.16%
1987	5.23%	-2.92%	-0.27%	3.02%
1988	16.81%	18.27%	10.70%	10.19%
1989	31.49%	47.80%	16.23%	15.61%
1990	-3.17%	-2.57%	6.78%	8.13%
1991	30.55%	14.61%	19.89%	19.25%
1992	7.67%	8.10%	9.39%	8.65%
1993	9.99%	14.41%	13.19%	10.59%
1994	1.31%	-7.94%	-5.76%	-4.72%
1995	37.43%	42.15%	27.20%	22.81%
1996	23.07%	3.14%	1.40%	3.04%
1997	33.36%	24.69%	12.95%	11.39%
1998	28.58%	14.82%	10.76%	9.44%
1999	21.04%	-8.85%	-7.45%	-1.69%
2000	-9.11%	59.70%	12.87%	9.45%
2001	-11.88%	-30.41%	10.65%	5.85%
2002	-22.10%	-30.04%	16.33%	1.63%
2003	28.70%	26.11%	5.27%	10.01%
2004	10.87%	24.22%	8.72%	6.03%
2005	4.91%	16.79%	5.87%	3.02%
2006 (p)	15.80%	20.95%	3.24%	3.94%
Geometric Mean	10.10%	8.80%	5.85%	5.45%
Arithmetic Mean	12.03%	11.14%	6.17%	5.73%
Standard Deviation	20.13%	22.55%	8.57%	7.89%
Median	14.31%	11.74%	4.14%	4.45%

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2006, 1952-2006, 1974-2006, and 1979-2006

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate: Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2006					
S&P Public Utility Index	8.80%	11.74%		11.14%	
Public Utility Bonds	5.45%	4.45%		5.73%	
Risk Differential	3.35%	7.29%	5.32%	5.41%	5.37%
1952-2006					
S&P Public Utility Index	10.99%	13.58%		12.53%	
Public Utility Bonds	6.17%	4.94%		6.47%	
Risk Differential	4.82%	8.64%	6.73%	6.06%	6.40%
1974-2006					
S&P Public Utility Index	12.79%	15.08%		14.77%	
Public Utility Bonds	8.55%	8.65%		8.90%	
Risk Differential	4.24%	6.43%	5.34%	5.87%	5.61%
1979-2006					
S&P Public Utility Index	13.42%	15.94%		15.27%	
Public Utility Bonds	8.96%	9.05%		9.29%	
Risk Differential	4.46%	6.89%	5.68%	5.98%	5.83%

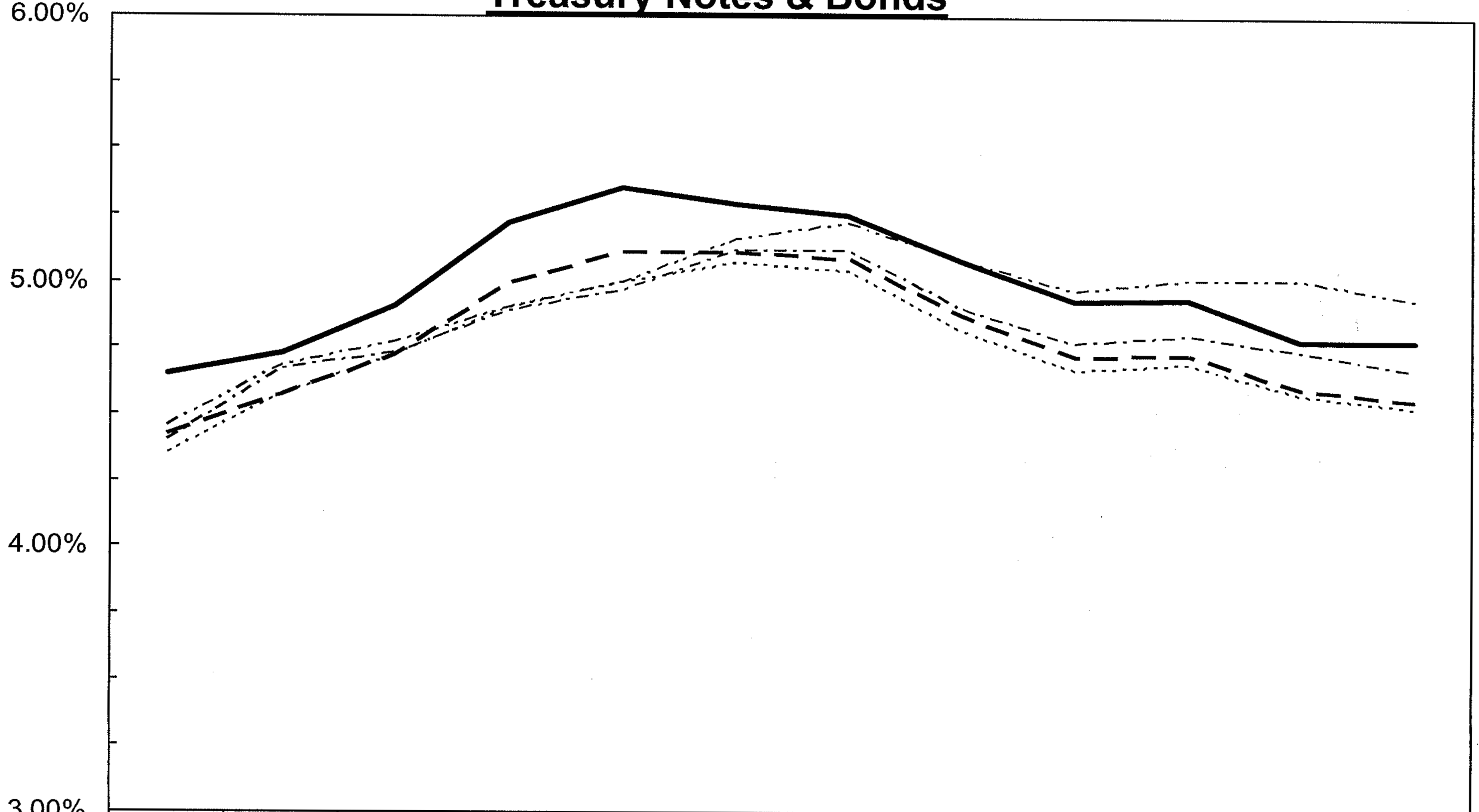
Value Line Betas

Gas Group

Chesapeake Utilities	0.60
Delta Natural Gas Company	0.55
EnergySouth, Inc.	0.60
Laclede Group, Inc.	0.90
Northwest Natural Gas	0.75
RGC Resources, Inc.	0.35
South Jersey Industries	0.70
Average	0.64

Source of Information:
Value Line Investment Survey
December 15, 2006

Yields on Treasury Notes & Bonds



	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06
1-Year	4.45%	4.68%	4.77%	4.90%	5.00%	5.16%	5.22%	5.08%	4.97%	5.01%	5.01%	4.94%
2-Year	4.40%	4.67%	4.73%	4.89%	4.97%	5.12%	5.12%	4.90%	4.77%	4.80%	4.74%	4.67%
5-Year	4.35%	4.57%	4.72%	4.90%	5.00%	5.07%	5.04%	4.82%	4.67%	4.69%	4.58%	4.53%
10-Year	4.42%	4.57%	4.72%	4.99%	5.11%	5.11%	5.09%	4.88%	4.72%	4.73%	4.60%	4.56%
20-Year	4.65%	4.73%	4.91%	5.22%	5.35%	5.29%	5.25%	5.08%	4.93%	4.94%	4.78%	4.78%

Yields for Treasury Constant Maturities
Yearly for 2001-2005
and the Twelve Months Ended December 2006

Years	1-Year	2-Year	3-Year	5-Year	7-Year	10-Year	20-Year
2001	3.49%	3.83%	4.09%	4.56%	4.88%	5.02%	5.63%
2002	2.00%	2.64%	3.10%	3.82%	4.30%	4.61%	5.43%
2003	1.24%	1.65%	2.10%	2.97%	3.52%	4.02%	4.96%
2004	1.89%	2.38%	2.78%	3.43%	3.87%	4.27%	5.04%
2005	3.62%	3.85%	3.93%	4.05%	4.15%	4.29%	4.64%
Five-Year Average	2.45%	2.87%	3.20%	3.77%	4.14%	4.44%	5.14%
Months							
Jan-06	4.45%	4.40%	4.35%	4.35%	4.37%	4.42%	4.65%
Feb-06	4.68%	4.67%	4.64%	4.57%	4.56%	4.57%	4.73%
Mar-06	4.77%	4.73%	4.74%	4.72%	4.71%	4.72%	4.91%
Apr-06	4.90%	4.89%	4.89%	4.90%	4.94%	4.99%	5.22%
May-06	5.00%	4.97%	4.97%	5.00%	5.03%	5.11%	5.35%
Jun-06	5.16%	5.12%	5.09%	5.07%	5.08%	5.11%	5.29%
Jul-06	5.22%	5.12%	5.07%	5.04%	5.05%	5.09%	5.25%
Aug-06	5.08%	4.90%	4.85%	4.82%	4.83%	4.88%	5.08%
Sep-06	4.97%	4.77%	4.69%	4.67%	4.68%	4.72%	4.93%
Oct-06	5.01%	4.80%	4.72%	4.69%	4.69%	4.73%	4.94%
Nov-06	5.01%	4.74%	4.64%	4.58%	4.58%	4.60%	4.78%
Dec-06	4.94%	4.67%	4.58%	4.53%	4.54%	4.56%	4.78%
Twelve-Month Average	4.93%	4.82%	4.77%	4.75%	4.76%	4.79%	4.99%
Six-Month Average	5.04%	4.83%	4.76%	4.72%	4.73%	4.76%	4.96%
Three-Month Average	4.99%	4.74%	4.65%	4.60%	4.60%	4.63%	4.83%

Source: Federal Reserve statistical release H.15

Measures of the Risk-Free Rate

The forecast of Treasury yields
per the consensus of nearly 50 economists
reported in the Blue Chip Financial Forecasts dated January 1, 2007

Year	Quarter	1-Year Treasury Bill	2-Year Treasury Note	5-Year Treasury Note	10-Year Treasury Note	30-Year Treasury Bond
2007	First	5.0%	4.8%	4.6%	4.6%	4.8%
2007	Second	4.9%	4.8%	4.7%	4.7%	4.8%
2007	Third	4.9%	4.8%	4.7%	4.8%	4.9%
2007	Fourth	4.8%	4.8%	4.8%	4.8%	5.0%
2008	First	4.8%	4.8%	4.8%	4.9%	5.0%
2008	Second	4.8%	4.8%	4.8%	4.9%	5.1%

I.U.R.C. No. 43208
I.U.R.C. No. 43209
Exhibit PRM-1
Page 25 of 28
Schedule 10 [5 of 6]

THE VALUE LINE Investment Survey®

Part 1
Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

January 19, 2007

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

18.4

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
17.3	14.1	19.6

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

1.7%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
1.7%	2.4%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

40%

26 Weeks Ago	Market Low 10-9-02	Market High 5-5-06
50%	115%	40%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXII, No. 21.
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Table 7

Basic Series and Portfolios

Summary Statistics of
Annual Retur
From 1926 to 2

I.U.R.C. No. 43208
I.U.R.C. No. 43209
Exhibit PRM-1
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Asset Class	1/1/26 to 12/31/06		
	Geometric Mean	Arithmetic Mean	Standard Deviation
Large Company Stocks	10.4	12.3	20.1
Small Company Stocks	12.7	17.4	32.7
Long-Term Corporate Bonds	5.9	6.2	8.5
Long-Term Government Bonds	5.4	5.8	9.2
Intermediate-Term Government Bonds	5.3	5.4	5.7
U.S. Treasury Bills	3.7	3.8	3.1
Inflation	3.0 E	3.1 E	4.3 E
90% Stocks/10% Bonds	10.1	11.7	18.1
70% Stocks/30% Bonds	9.3	10.3	14.5
50% Stocks/50% Bonds	8.4	9.0	11.5
30% Stocks/70% Bonds	7.3	7.7	9.3
10% Stocks/90% Bonds	6.1	6.4	8.8

E = Estimated

Comparable Earnings Approach
Using Non-Utility Companies with
Timeliness of 4; Safety Rank of 1, 2 & 3; Financial Strength of B+, B++ & A;
Price Stability of 90 to 100; Betas of .35 to .90; and Technical Rank of 2 & 3

Company	Industry	Timeliness Rank	Safety Rank	Financial Strength	Price Stability	Beta	Technical Rank
Assoc. Banc-Corp	BANKMID	4	2	B++	100	0.90	3
Clorox Co.	HOUSEPRD	4	2	B++	95	0.60	3
Commerce Bancshs.	BANKMID	4	1	A	100	0.90	3
Compass Bancshares	BANK	4	2	B++	100	0.90	3
Dentsply Int'l	MEDSUPPL	4	2	B++	95	0.70	3
First Midwest Bancorp	BANKMID	4	2	B++	95	0.90	3
Hormel Foods	FOODPROC	4	1	A	95	0.75	3
Kellogg	FOODPROC	4	2	B++	100	0.65	3
Weis Markets	GROCERY	4	1	A	90	0.80	3
Wiley (John) & Sons	PUBLISH	4	3	B+	90	0.75	3
Average		4	2	B++	96	0.79	3
Gas Group	Average	4	2	B++	96	0.64	2

Source of Information: Value Line Investment Survey for Windows, January, 2007

Comparable Earnings Approach
Five -Year Average Historical Earned Returns
for Years 2001-2005 and
Projected 3-5 Year Returns

Company	2001	2002	2003	2004	2005	Average	Projected 2009-11
Assoc. Banc-Corp	16.8%	16.6%	17.0%	12.8%	13.8%	15.4%	13.5%
Clorox Co.	20.2%	23.8%	42.3%	35.5%	35.5%	31.5%	49.0%
Commerce Bancshs.	14.3%	14.1%	14.2%	15.4%	16.7%	14.9%	13.0%
Compass Bancshares	15.8%	16.3%	18.3%	18.1%	18.0%	17.3%	12.5%
Dentsply Int'l	18.0%	17.5%	15.4%	13.6%	17.4%	16.4%	15.0%
First Midwest Bancorp	18.4%	18.3%	17.8%	18.6%	18.6%	18.3%	20.5%
Hormel Foods	18.3%	17.0%	14.8%	15.6%	16.1%	16.4%	16.0%
Kellogg	61.1%	79.4%	54.5%	39.5%	42.9%	55.5%	30.5%
Weis Markets	10.1%	10.4%	9.5%	10.0%	10.5%	10.1%	10.5%
Wiley (John) & Sons	23.5%	22.3%	20.7%	23.0%	31.0%	24.1%	13.5%
Average						22.0%	19.4%
Median						16.8%	14.3%